United States and World Resources of Energy[1/]

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Abstract

Energy resources must be viewed as a range extending from reserves in known deposits minable at present prices to resources that may become usable in the future through further exploration and technologic advance. Appraised in this framework, domestic resources of the fossil fuels of the types now considered usable contain 5.5 to more than 130 Q (i.e., 10^{18} Btu), and if very low grade organic-rich deposits are included, the potential may be more than 1,600 Q. World resources contain about 23 to more than 475 Q, and if very low grade resources are considered the potential may be more than 20,000 Q.

The energy potential of uranium resources in the United States ranges from about 0.16 to more than 280,000 Q, the larger figure depending not only on the use of low-grade ore but also on the successful development of the breeding process. The energy potential of world uranium resources similarly ranges upward from 0.34 Q to an order of magnitude of 5 million Q. The energy potential of thorium resources of the United States ranges from 7 to 420,000 Q, and of the world from 48 to about 7 million Q. If nuclear fusion can be controlled for power generation, the potential energy from resources of deuterium and $lithium^6$ are orders of magnitude larger than the fissionable mineral resources. Deuterium alone contains potential energy of 7.5 billion Q. Water power, geothermal energy, solar energy, and tidal power also represent large potential sources.

The almost staggering contrast between the magnitude of known reserves minable at present prices and potential resources minable only at higher prices or more advanced technology underscores the critical importance of research, exploration, and development in meeting future needs.

Introduction

Most energy source materials lie hidden beneath the earth's surface and their extent is difficult to determine. Compounding the problem of appraising the magnitude of energy resources is the fact that the kinds of materials usable as energy sources are constantly changing as the advance of technology permits us to recover energy from materials that were once too low grade or too inaccessible to mine, and to utilize materials that were not previously visualized as economical sources of energy.

These factors, of course, combine to enlarge our usable supplies of mineral fuels. Development of geophysical techniques for petroleum exploration, expansion of geologic knowledge concerning the habitat of oil, improvement in drilling techniques, and development of methods of secondary recovery are among the scientific and technologic advances that have made it possible to find and recover a far larger amount of oil than was thought to exist a few decades ago. Similarly, technologic advances in transportation have made possible widespread and quantitatively important use of natural gas, whereas the great bulk of it was discarded before. Uranium and other nuclear materials were not even thought of as commercial sources 25 years ago, and oil shale and other organic-rich shales, not yet used as energy sources except on an insignificant scale, almost certainly will become important in the future.

1/ Publication authorized by the Director, U. S. Geological Survey.

The concept that supplies of usable minerals are extended by the advance of scientific knowledge forces three important conclusions pertinent to preparation of resource estimates: 1) even though searching estimates are prepared, they can never represent a final inventory of resources of the commodity in question, but are at best a quotation reflecting the status of knowledge of resources at the time the estimates are made; 2) in making and interpreting estimates of mineral resources it is necessary to differentiate between deposits that are known and closely appraised and those that are either not closely appraised or are as yet undiscovered but are believed to exist, on the basis of geologic evidence; and 3) it is necessary to distinguish between deposits that are minable or recoverable at present costs and those that cannot be mined now but might be recovered under more favorable economic or technologic conditions. To appraise the future availability of energy supplies, therefore, several categories of resources are examined:

1) Known recoverable reserves--deposits whose location and general magnitude are established and that are recoverable at or close to present prices and with established technology. Generally, the figures include estimates of other authors described as measured, indicated and inferred, or proved, possible, and probable reserves [for definitions, see F. Blondel and S. G. Lasky, Mineral reserves and mineral resources: Econ. Geol. v. 51, 1956, p. 686-697].

2) Undiscovered recoverable resources--deposits whose specific location is unknown but whose presence and character are indicated by geologic evidence.

3) Known marginal and submarginal resources--deposits whose location and general magnitude are established and that may become recoverable as technology advances or economic conditions change, but cannot be recovered now.

4) Undiscovered marginal and submarginal resources--deposits whose specific location is unknown but whose presence and character are indicated by geologic evidence.

Estimates of reserves and resources depend upon the methods utilized, the assumptions adopted, and the basic information available. Wide divergence in estimates prepared by different observers is therefore not uncommon. Over the past few years, for example, estimates of crude oil "reserves" have ranged from 31 to 590 billion barrels. Some of these are estimates of reserves in known recoverable deposits only, and some include resources that may eventually be found and recovered as technology advances. Some are projections based on existing knowledge or economic conditions, and others assume that technologic or economic changes will take place. And some may be purely statistical projections of the past and present rates of discovery, while others take account of geologic concepts of origin and accumulation.

Knowledge of resources is best represented by estimates that reflect a range in values and assumptions, which is accomplished by the four definitions above and by the estimates given in subsequent tables. The totals presented here are generally larger than those published previously, mainly because the estimates here take more account of undiscovered and marginal resources. Seen in this perspective, the differences in estimates of recent years are not so large as might first appear. For example, the estimate of known recoverable reserves of petroleum in table 1 corresponds to the minimum estimates of recent years; those of undiscovered recoverable resources correspond approximately to estimates of "ultimate" reserves that allow for new discoveries but not much change in technologic or economic conditions. The estimates of undiscovered marginal and submarginal resources represent resources of potential value that are commonly excluded from other resource estimates.

Most of the estimates here were prepared first to serve the needs of the Natural Resources Committee of the Federal Council for Science and Technology [Federal

Council for Science and Technology, Committee on Natural Resources, 1963, Research and development on natural resources: Washington, D. C., U. S. Govt. Printing Office, 134 p.7, and with some modifications in coverage they have been used for other recent studies undertaken within the Federal Government /see also U. S. Dept. Interior, Energy Policy Staff, 1963, Supplies, costs, and uses of the fossil fuels: Washington, D. C., 34 p. 2 figs.7. They are provisional, not only in the sense that all resource estimates are provisional, but also in the sense that they will be replaced shortly by new estimates currently in preparation by members of the U. S. Geological Survey.

Fossil fuels

The energy content of known domestic reserves of fossil fuels recoverable at or close to present prices and with established technology is about 5.5 Q (quintillion or 10^{18} Btu), and that of undiscovered and/or marginal and submarginal resources, minable under changed conditions or higher prices, is a little more than 124 Q (table 1). These amounts are respectively equivalent to about 0.2 and 4.8 trillion tons of coal, measured in terms of the standard equivalent of 26 million Btu per ton of bituminous coal. Of the presently minable deposits, coal contains nearly 84 percent of the total energy and most of the remainder is about equally divided among petroleum and natural gas liquids, natural gas, and shale oil. Oil shale deposits contain about 28 percent of the marginal and submarginal resources; shales, not included in the above estimates, containing 10 percent or more organic matter, hold an energy potential of 220 Q, and those with 5-10 percent organic matter have a potential of about 1,600 Q.

The energy content of known recoverable world reserves of fossil fuels is about 23 Q. Undiscovered and/or marginal and submarginal resources contain about 452 Q (table 2). Shales with more than 5 percent organic matter probably have an energy potential of more than 20,000 Q.

Nuclear fuels

Known United States reserves of uranium minable at a price of $5-$10 per pound of U_3O_8 are about 142,000 tons, and 181,000 tons additional have already been delivered to the Atomic Energy Commission (table 3). Assuming complete burn-up of contained U^{235}, the energy equivalent of delivered and minable uranium is 0.16 Q; assuming complete burn-up of U^{235} and U^{238} (possible only with breeding), the energy equivalent is about 22 Q. Unappraised and undiscovered resources of the same quality as those being mined probably contain energy equivalents of 0.35-54 Q (depending on burn-up). Lower-grade uraniferous deposits, which with present technology would cost up to $100 or more a pound of U_3O_8 to mine, contain energy equivalents of 2,000-280,000 Q (depending on burn-up). World uranium reserves minable at $5-$10 a pound are about 700,000 tons, with an energy equivalent of 0.34-48 Q, and may be far larger (table 4).

Thorium will be available as an energy source only when the breeder reactor is practicable, and because it has not been in much demand its resources are not as well known as those of uranium. Known domestic recoverable reserves minable at $5-$10 a pound of U_3O_8 are 100,000 tons, with an energy equivalent of 7 Q, assuming complete burn-up (table 5). Unappraised and undiscovered resources of the same and lower quality probably contain the energy equivalent of more than 420,000 Q. World reserves minable at $10 a pound or less contain the energy equivalent of 48 Q and the energy equivalent in lower grade resources are far larger (table 6).

The fusion reaction now yields only explosion energy. If it can be sustained and controlled for the production of electric power, the natural fuels would be deuterium and lithium[6]. According to Friedman and others /Friedman, I., Redfield, A. P., Schoen, B., and Harris J., 1964, The variation of the deuterium content of natural waters in the hydrologic cycle: Rev. Geophysics, v. 2, p. 177-2247, the oceans contain about 2.5×10^{13} short tons of deuterium, the energy equivalent of which is about 7.5 billion Q.

Table 1. Provisional estimates of United States resources of fossil fuels 1/
(Energy equivalent in 10^{18} Btu shown in parenthesis)

	Known recoverable reserves 2/	Undiscovered recoverable resources	Known marginal and submarginal resources	Known marginal and submarginal resources
Coal (short tons)	220×10^9 (4.6)	Not estimated	$1,400 \times 10^9$ (29)	$2,600 \times 10^9$ (55)
Petroleum (barrels)	47×10^9 (0.272)	200×10^9 (1.16)	40×10^9 (0.23)	300×10^9 (1.74)
Natural gas (cu. ft.)	276×10^9 (0.285)	$1,200 \times 10^{12}$ (1.24)	Not estimated	850×10^{12} (0.88)
Natural gas liquids (barrels)	7.7×10^9 (0.035)	30×10^9 (0.140)	Not estimated	60×10^9 (0.28)
Oil in bituminous rock (barrels)	1.3×10^9 (0.008)	Not estimated	Not estimated	10×10^9 (0.058)
Shale oil (barrels)	50×10^9 (0.29)	Not estimated	$2,000 \times 10^9$ (11.6)	$4,000 \times 10^9$ (23.2)
Total (rounded) energy	(5.5)	(2.6)	(41)	(81)
Grand (rounded) total, all classes	(130)			

Energy equivalents: 1 short ton of coal = 21×10^6 Btu; 1 barrel petroleum, oil from bituminous rock, or shale oil = 5.8×10^6 Btu; 1 barrel natural gas liquids = 4.62×10^6 Btu; 1 cubic foot natural gas = 1,035 Btu.

1/ Compiled by D. C. Duncan and V. E. McKelvey, U. S. Geological Survey. Explanation, definitions, and sources of data are on the following pages.

2/ As defined here, this category includes measured, indicated, and inferred reserves. Estimates of indicated and inferred reserves of oil, gas, and natural gas liquids are not available, however, the estimates shown for them are proved (i.e., measured) reserves and therefore not wholly comparable to the estimates shown for coal, oil in bituminous rocks, and shale oil.

Explanation of resource estimates

Coal. Known recoverable reserves are those in thick coal beds lying at depths less than 1,000 feet, and assume 50 percent recovery of coal in place. The minimum thickness for beds of bituminous and higher rank coal included in the estimate is 3.5 feet and that of subbituminous and lower rank coal is 10 feet.

Known marginal and submarginal resources include coal left in first mining of known recoverable reserves, coal in thin beds at shallow depth, and coal lying at depths between 1,000 and 3,000 feet below surface. The estimate refers to coal in place, and includes coal in the measured, indicated, and inferred categories of P. Averitt, U. S. Geol. Survey Bull. 1136 (with additional data reported by H. Beikman, et al., Washington Division of Mines and Geol. Bull 47), less that reported here in the known recoverable class, rounded to two significant figures.

Undiscovered marginal and submarginal resources refer to coal believed to be in place to depths of 6,000 feet. No separate estimate has been prepared of undiscovered thick coal at shallow depths. Compiled from estimates by M. R. Campbell, Coal Resources of the World, 1913, less the sum of known reserves and known marginal and submarginal resources, rounded to two significant figures.

Petroleum. Known recoverable reserves include proved reserves of American Petroleum Institute (31 billion barrels as of Dec. 31, 1963) plus reserves economically recoverable by established secondary-recovery methods in practice (16 billion barrels) as estimated by Interstate Oil Compact Commission as of January 1, 1962. The API estimate includes primary reserves plus those secondary reserves recoverable by methods already in practice in each field. The IOCC estimates refer to oil recoverable by established methods but not yet in practice in all fields.

Known marginal and submarginal resources include additional oil in known deposits considered to be physically recoverable by newer secondary-recovery methods but possibly at increased costs. The original oil in place in known deposits is estimated by IOCC to be 346 billion barrels. Production of 73 billion barrels to January 1963, plus primary and secondary reserves of the above estimates total 160 billion barrels or 46 percent of the estimated oil in place. A somewhat larger recovery, as much as 65 percent of the oil in place, is considered possible eventually with future improvements in recovery techniques; hence the known marginal and submarginal resources might be as much as 110 billion barrels.

Undiscovered recoverable resources include oil in possible extensions of known field and in undiscovered fields thought to be discoverable under present conditions. Both estimates are based on unpublished estimates of A. D. Zapp, U. S. Geological Survey, who derived them from analysis of extent of favorable ground compared with total footage of exploratory drilling completed thus far. For outline of method, see A. D. Zapp, U. S. Geol. Survey Bull. 1142-H.

Undiscovered marginal and submarginal resources include petroleum accumulations thought to be present in less favorable areas, at greater depths, and in less productive accumulations than those considered commercially usable under present conditions.

Natural gas. Known recoverable reserves include proved reserves as of the close of 1963, from American Gas Association and American Petroleum Institute. No estimate has been prepared of known marginal and submarginal gas resources.

Estimates of undiscovered recoverable resources are based on a ratio of 6,000 feet of gas discovered per barrel of oil. Recent estimates of this ratio range from 6,000 to 8,000 cu. ft. of gas per barrel of oil, and hence the undiscovered recoverable resources of gas may be as high as 1,500 or 1,600 x 10^{12} cu. ft.

Undiscovered marginal and submarginal resources are Zapp's unpublished estimates of resources not economic now. Because a larger fraction of natural gas in subsurface reservoirs is recoverable than oil under present circumstances, the estimate of submarginal resources of gas is less generous than that for oil.

Deep drilling, however, might produce much larger quantities, for experience already indicates that there is some increase in concentration of natural gas with depth. The estimate does not include possible large sources, such as many known unproduced natural gas accumulations reported as "shows" that were considered uneconomic when found, pore-space gas in coal and black shale, or synthetic gas from black shale or coal. For example: the Chattanooga shale and its stratigraphic equivalents probably contain about 8×10^{15} cu. ft. of gas equivalent if processed by hydrogenolysis. The four trillion tons of coal in the United States may also contain as much as 8×10^{15} cu. ft. of entrapped methane gas, some fraction of which might be recoverable in the future. The carbonaceous shales associated with coal might contain an additional 4×10^{15} cu. ft. of gas and some marine black shales such as the Chattanooga and equivalents, may contain comparable or larger amounts of such gas in pore space.

Natural gas liquids. Known recoverable reserves are rounded from API-AGA estimates for the close of 1963 which indicate a ratio of about 25 barrels of liquids economically recoverable per million cubic feet of gas. Undiscovered recoverable resources are based on the same ratio of natural gas to natural-gas-liquids. Undiscovered marginal and submarginal resources are Zapp's unpublished estimate which assumes more complete recovery and greater quantities of natural-gas-liquids in the deeper gas accumulations.

Oil in bituminous rock. Known recoverable resources include minimal estimates of some deposits for which ready data are at hand; assumed recovery is 50 percent of the oil in place. An estimate of 10 billion barrels from L. G. Weeks, 1960, Geotimes, v. 5, no. 1, p. 20, is the basis for the figure on undiscovered marginal and submarginal resources; it includes a number of known deposits that are unappraised.

Shale oil. Known recoverable reserves include oil recoverable from higher grade oil shale in Colorado and Utah in beds 25 feet or more thick, yielding about 30 gallons of oil per ton of rock, and lying at depths less than 1,000 feet below surface. Assumed recovery is 50 percent of the oil content of the shale. Known marginal and submarginal resources include shale left in first mining of the known recoverable reserves, estimates of the full oil content of similar higher grade deposits at depths greater than 1,000 feet below surface, and estimates of thin and low-grade oil shale, with minimum yield of 10 gallons of oil per ton and minimum thickness of 5 feet and to depths as much as 10,000 feet below surface.

Undiscovered marginal and submarginal resources include a speculative estimate of equivalent oil in possible extensions of some major known oil shale deposits, yielding 10 gallons or more oil per ton to depths as much as 20,000 feet. A much larger amount of incompletely appraised shale is known and inferred. Shales not included in the estimates shown on the table but containing 10 percent or more organic matter probably contain about 9 trillion tons of organic matter with a potential energy content of 220 Q. Shale containing 5 to 10 percent organic matter probably contains an energy equivalent of 1,600 Q.

Table 2. Provisional estimates of world resources of the fossil fuels (Energy equivalent in 10^{18} Btu shown in parenthesis)

	Known recoverable reserves	Undiscovered and/or marginal and submarginal resources
Coal (short tons) 1/	850×10^9 (18)	$15,150 \times 10^9$ (320)
Petroleum (barrels) 2/	300×10^9 (1.7)	$4,000 \times 10^9$ (23)
Natural gas (cu. ft.) 3/	$1,800 \times 10^{12}$ (1.9)	$19,000 \times 10^{12}$ (20)
Natural gas liquids (barrels) 4/	45×10^9 (0.21)	700×10^9 (3.2)
Oil in bituminous rocks (barrels) 5/	40×10^9 (0.23)	$1,060 \times 10^9$ (6.1)
Shale oil (barrels) 6/	150×10^9 (0.87)	$13,600 \times 10^9$ (79)
Total (rounded) energy in fossil fuels (10^{18} Btu)	23	452

1/ Known recoverable reserves consist of half of the measured reserves of coal and lignite reported by Parker (World Power Conference Survey of energy resources, 1962: Central Office World Power Conference, London, p. 10), adjusted to make U. S. reserves conform with those shown in table 1, and to incorporate a different approximation of minable reserves in the U.S.S.R. The latter is based on the 1956 estimated quoted by J. A. Hodgkins (Soviet power, energy resources, production and potential: Prentice Hall, 1961) that 2.09 trillion metric tons of coal in the U.S.S.R. lie above a depth of 300 meters; it is assumed that the distribution of these beds by thickness is similar to that in the U. S., so that 30 percent of the total, or 695,000 short tons, is in thick beds, half of which is recoverable.

Undiscovered or marginal resources are those reported by Parker, adjusted to make U. S. reserves conform with those shown in table 1 and to incorporate the 1956 estimate of U.S.S.R. coal and lignite above a depth of 1,800 meters (9.6 trillion tons), less known recoverable reserves

2/ Recoverable reserves are taken as the U. S. figure from table 1, plus proved reserves in remainder of world (Oil and Gas Jour., v. 60, no. 53, p. 85, 1962). Undiscovered or marginal and submarginal resources are the undiscovered recoverable, known marginal, and undiscovered marginal and submarginal resources for the other areas; the latter are based on an extrapolation of U. S. estimates to the remainder of the world according to area of sedimentary rocks and to the geologic favorability factors derived from L. G. Weeks, 1959, Where will energy come from in 2059?: Petroleum Engineer, v. 31, no. 9, p. A24-31).

3/ There are no available estimates of proved world gas reserves. Hence, known recoverable reserves are estimated on the basis that 6,000 cu. ft. of gas are expectable per barrel of oil. Estimates of undiscovered and marginal and submarginal resources are unpublished ones of Zapp and allow a somewhat lower gas-oil ratio for marginal resources.

4/ There are no available estimates of proved world reserves of natural gas liquids. Known recoverable reserves are estimated on the basis that natural gas contains about 24 barrels of natural gas liquids per million cubic feet of gas as in the U. S. Estimates of undiscovered and marginal and submarginal resources are unpublished ones of Zapp and allow a somewhat larger ratio between liquids and gas in marginal and submarginal resources.

5/ Estimates of known recoverable reserves include only deposits in U. S. and Canada. Canadian reserves of 37.9×10^9 barrels have been calculated by H. L. Berryhill, Jr., from information on extent of deposits now obtainable by open-pit mining methods reported by Oil and Gas Jour., v. 59, July 31, 1961, p. 253, and August 14, 1961, p. 79, and on the assumption that 75 percent of the oil in place is recoverable. Undiscovered and marginal and submarginal resources are from L. G. Weeks (less known reserves), op. cit., 1960.

6/ From unpublished estimates of D. C. Duncan. Known recoverable reserves generally are limited to those deposits yielding more than 25 gallons of oil per ton, in zones 25 feet or more thick, and lying less than 1,000 feet below the surface, and assume 50 percent recovery is mining. In certain foreign areas, however, where an oil shale industry is already established, deposits of the grades and thicknesses currently mined are considered recoverable under certain conditions; in some places deposits containing as little as 12 gallons per ton are mined by open-pit methods. Marginal and submarginal oil shale deposits are those yielding 10 gallons or more per ton and includes possible major extensions of known deposits. Other unappraised organic-rich-shale deposits extending to depths of 20,000 feet, and containing 10 percent or more organic matter, probably contain energy equivalent of about 4,000 Q; deposits containing 5 to 10 percent organic matter probably contain an energy equivalent of about 20,000 Q. These unappraised deposits are not included in the estimates shown on the table.

Table 3. Provisional estimates of United States resources of uranium 1/ (Short tons of U. Energy equivalent to 10^{18} Btu shown in parenthesis) 2/

Present cost (dollars per pound of U) 3/	Known deposits	Unappraised and undiscovered resources
5 - 10 4/	142,000 (0.07 - 10)	770,000 (0.38 - 54)
10 - 30 5/	140,000 (0.07 - 10)	500,000 (0.24 - 35)
30 - 100 6/	21,300,000 (6 - 860)	20,000,000 (10 - 1,400)
100 - 500 7/	--	4,000,000,000 (1,969 - 280,000

1/ Estimates of known deposits recoverable at a cost of $5-10 per pound are by the Atomic Energy Commission; most other estimates prepared by the U. S. Geological Survey.

2/ The minimum energy equivalent is that contained in U^{235} and assumes complete burn-up. The maximum is the total contained in U^{235} as well as U^{238}. Conversion factor: 1 short ton U = 7 x 10^{13} Btu.

3/ Based on specific estimates by AEC of mining and processing costs of various types of deposits, assuming present economic and technologic conditions.

4/ Uranium already mined and delivered to AEC totals 181,000 tons and should be added to known reserves to represent uranium available under present conditions. Known reserves, estimated by AEC, include 135,000 tons in western sandstone deposits averaging about 0.21 percent U, and 7,000 tons in western vein deposits averaging about 0.21 percent U. Undiscovered resources estimated by A. P. Butler, Jr. (unpublished data), include approximately 700,000 tons in sandstone deposits in the Colorado Plateau and adjacent areas and 60,000 tons in vein deposits in the western states.

5/ Known deposits include a) about 23,000 tons recoverable as by-product from the manufacture of triple superphosphate and similar products, taken as 15 percent (the proportion of total phosphate production currently treated by such methods) of the 90,000 tons estimated by V. E. McKelvey (unpublished data, 1952) to occur in beds 3 feet or more thick, and containing more than 30 percent P_2O_5 and lying 1,000 feet below entry level in the western phosphate field and of the 65,000 tons estimated by J. B. Cathcart (unpublished data, 1951) to occur in currently recoverable phosphate concentrates in the Florida field; b) about 8,000 tons in western sandstone deposits and 1,000 tons in vein deposits containing more than 0.1 percent U but not considered by AEC to be minable at present prices; c) 95,000 tons in sandstone deposits containing 0.04 to 0.1 percent U, estimated by A. P. Butler, Jr. from the fact that assay data show such materials to be present in amounts equal to about two-thirds of the higher grade ore; and d) 12,000 tons in uranium-bearing pyrochlore in potassic syenite in the Bearpaw Mountains (W. T. Pecora, unpublished data). Unappraised and undiscovered resources include a) 30,000 tons in by-product recovery from the 200,000 tons estimated by J. B. Cathcart (unpublished data) in potential resources in the North Carolina phosphate field; b) 460,000 tons in low-grade western sandstone deposits; and c) 20,000 tons in uranium-bearing pyrochlore deposits.

6/ Known resources include a) about 130,000 tons in the remainder of the known phosphate resources mentioned above (assumed to be recoverable as a principal product in this cost range; b) about 65,000 tons in phosphate concentrates in the Bone Valley formation of Florida; c) about 100,000 tons in aluminum phosphates in the Bone Valley leached zone; d) 6,000,000 tons estimated by Andrew Brown in the Chattanooga shale of Tennessee and adjacent states (averaging about 0.006 percent U); and e) 6,000,000 tons estimated by A. P. Butler, Jr., in the Conway alkalic granite, N. H., to a depth of 1,000 feet. Unappraised resources include

a) 600,000 tons in high-grade phosphate rock in the western field lying more than 1,000 feet below entry level; b) 1,300,000 tons in phosphate containing about 0.0008 percent U and more than 24 percent P_2O_5 in the western field; c) 200,000 tons estimated by A. P. Butler, Jr., (from data of G. H. Espenshade) to occur in phosphate in northern Florida; d) 1,000,000 tons in phosphate nodules, averaging about 0.005 percent, in the Hawthorne formation of Florida; e) 170,000 tons in the North Carolina phosphates; and f) 16,000,000 tons estimated by V. E. Swanson to occur in the Chattanooga shale in beds containing 0.004 percent or more U.

7/ Includes a) 2 billion tons estimated by V. E. Swanson to occur in the Chattanooga shale and equivalents in central United States in beds averaging about 0.003 percent U; b) 2 billion tons in large granitic bodies (Pikes Peak, Marquette Co., Michigan, Wisconsin, Minnesota, Idaho batholith, California batholith, S. California batholith, N. California batholith, N. Washington batholith, Appalachians, and New England), containing about 4 ppm U above a depth of 1,500 feet (estimated by AEC).

Table 4. Provisional estimates of world uranium reserves 1/
(Energy equivalent to 10^{18} Btu shown in parenthesis 2/)

Country	Short tons
United States	142,000 (0.07 - 10)
Canada	236,000 (0.11 - 16)
South Africa	127,000 (0.06 - 9)
France	34,000 (0.02 - 2.4)
Australia	13,700 (0.007 - 0.96)
Sino-Soviet Bloc	110,000 - 400,000 (0.05 - 0.2; 7.7 - 28)
Other 3/	21,000 (0.01 - 1.5)
Total (rounded) non Communist world	575,000 (0.28 - 40)
Total (rounded) world 4/	685,000 - 1,085,000 (0.34 - 0.53; 48 - 76)

1/ Known deposits minable at $5-10 per pound; those for the United States, Canada and South Africa represent material minable at $8 per pound or less. Estimates of reserves in Sino-Soviet Bloc from the McKinney Staff, Report to the Joint Committee on Atomic Energy, Congress of the United States, 1960, v. 4, p. 1613. Estimates on all other countries supplied by R. D. Nininger, U. S. Atomic Energy Commission.

2/ The minimum energy equivalent is that contained in U^{235} and assumes complete burn-up. The maximum is the total contained in U^{235} and U^{238}. Conversion factor: 1 short ton U = 7×10^{13} Btu.

3/ Argentina, Congo, Germany, India, Japan, Mexico, Portugal, and Spain.

4/ Undiscovered deposits of the same quality are estimated to be 770,000 tons (see table 3); data are not available for similar country by country estimates, but the relation between crustal abundance of the elements and their minable resources suggests that potential world resources in deposits of this quality are of the order of 45 million tons (see V. E. McKelvey, Am. Jour. Sci., v. 258A, p. 234-241, 1960). Despite the lack of quantitative estimates of total marginal or submarginal resources, several examples indicate that their potential is enormous. The alum black shale of Sweden contains about 850,000 tons U in known deposits averaging 0.03 percent U_3O_8, and another 1.7 million tons in known deposits averaging about 0.02 percent; unappraised resources may be of the order of 10 million tons. North African phosphorites contain about 2 million tons U (R. D. Nininger and C. J. Gardner, U. S. Atomic Energy Commission TID-8207, p. 3, 1960). Each of the major types of low-grade resources is known qualatively in other parts of the world and an estimate of potential world resources based on an extrapolation of those listed in table 3 to the rest of the world on the basis of the proportionately larger area involved--say 4 billion tons x 17.3= about 70 billion tons (approximately 5 million Q)--is probably of the right order of magnitude.

Table 5. Provisional estimates of United States resources of thorium 1/ (Short tons of Th. Energy equivalent to 10^{18} Btu shown in parenthesis) 2/

Present cost (dollars per pound ThO_2 3/	Known deposits	Unappraised and undiscovered resources
5 - 10 4/	100,000 (7)	800,000 (56)
10 - 30 5/	100,000 (7)	1,700,000 (120)
30 - 100 6/	---	30,000,000 (2,100)
100 - 500 7/	---	6,000,000,000 (420,000)

1/ Estimates of thorium in known deposits in the $5-10 cost range prepared by the AEC; most other estimates prepared by the U. S. Geological Survey.

2/ Assumes complete recovery. Conversion factor: 1 short ton Th = 7×10^{13} Btu.

3/ Based on specific estimates by AEC of mining and processing costs of various types of deposits, assuming present economic and technological conditions.

4/ Known deposits include about 88,000 tons in vein deposits in the Lemhi Pass area of Idaho (B. J. Sharp, D. L. Hetland, and A. E. Granger, AEC, unpublished data); about 4,000 tons in Idaho and Carolina monazite placers (AEC estimate); and about 16,000 tons in the Goodrich quartzite, Michigan (R. C. Vickers, U. S. Geol. Survey Bull. 1030-F). The estimate of unappraised and undiscovered resources is a speculative one by J. C. Olson, U.S.G.S., that includes 300,000 tons of potential resources in the Lemhi Pass district estimated by Sharp, et al. as well as potential resources in veins in about 20 other promising districts.

5/ Known deposits include 53,000 tons in Carolina placers (W. C. Overstreet, P. K. Theobald, and J. W. Whitlow, Am. Inst. Mining Eng. Trans., v. 214, p. 709-714, (1959) and 50,000 tons in the Goodrich quartzite. Unappraised and undiscovered resources include 150,000 tons in the Goodrich quartzite; 10,000 tons in Idaho and Montana placers (D. E. Eilertson and F. D. Lamb, U. S. Bur. Mines RME-3140, U. S. Atomic Energy Comm. Tech. Info. Service, Oak Ridge, Tenn.); 120,000 tons in a monazite placer off the mouth of the Apalachicola River, Florida (W. F. Tanner, A. Mullins, and J. D. Bates, Econ. Geol., v. 56, p. 1079-1087, 1961); 8,000 tons in Arkansas bauxite (estimated by Olson from data of J. A. S. Adams, and C. E. Weaver, Am. Assoc. Petroleum Geologists Bull., v. 42, p. 387-430, 1958); 14,000 tons in quartz bostonites in Colorado to a depth of 1,000 feet (G. Phair, U.S.G.S. unpublished data, 1962); 1,000,000 tons in hornblende-albite syenite, Wet Mountains, Colo., to a depth of 1,000 feet (M. R. Brock, U.S.G.S. unpublished data, 1962); 180, tons in shonkinite, Mountain Pass, Calif., to a depth of 1,000 feet (J. C. Olson, U.S.G.S. unpublished data, 1962); 4,500 tons in gneiss, Mass., to a depth of 1,000 feet (D. H. Johnson, U. S. Geol. Survey TEI-69, U. S. Atomic Energy Comm. Tech. Info. Service, Oak Ridge, Tenn.); 10,000 tons in thorium-bearing veins, Wet Mountain, Colo., to a depth of 50 feet (M. R. Brock, U.S.G.S. unpublished data, 1962); 17,000 tons in Cretaceous black sand deposits in the western states (V. T. Dow, J. V. Beatty, U. S. Bur. Mines Rept. Inv. 5860); and a speculative estimate by J. C. Olson of 200,000 tons in thorium-bearing veins containing 0.03-0.3 percent Th to depths of 1,000 feet in the Wet Mountains, Colo., and elsewhere.

6/ Conway granite, N. H., to depth of 1,000 feet. In addition, the Silver Plume granite and Pikes Peak granite, Colo., probably contain 50,000 tons and 100,000, respectively, to depth of 1,000 feet, in rocks with thorium contents of 90 and 50 ppm (G. Phair, U.S.G.S. unpublished data).

7/ Large granitic bodies containing 12-30 ppm Th to depth of 1,500 feet, including Pikes Peak granite, Marquette County, Mich., Wisconsin, Minnesota, Idaho batholith, California batholith, S. California batholith, N. California batholith, N. Washington batholith, Appalachians, and New England. Estimated by AEC.

Table 6. Provisional estimates of world thorium reserves, minable at $10 per pound or less1/ (Energy equivalent to 10^{18} Btu shown in parenthesis; assumes complete burn-up)

Area	Short tons
United States	100,000 (7)
Canada	175,000 (12)
Brazil	25,000 (2)
Africa	45,000 (2)
India, Ceylon, Afghanistan, Nepal, Pakistan2/	220,000 (15)
Sino-Soviet Bloc	90,000 (6)
Australia	45,000 (3)
Total3/	700,000 (48)

1/ Estimates for the United States from table 10. Estimate for Australia from Bowie, S. H. U., 1959, The uranium and thorium resources of the Commonwealth: Royal Soc. Arts Jour., v. 107, p. 706; those for other areas from McKinney report, op. cit., p. 1612-1613.

2/ An additional 250,000 tons is possible in the inland placers of Bihar and West Bengal, which have not been thoroughly explored.

3/ Undiscovered resources of the same quality are potentially much larger. On the basis of a comparison between thorium reserves and the known areal extent of metamorphic and igneous rocks (to which thorium deposits are genetically related), world resources would be expected to be 3 6 million tons, taking the United States and the base for extrapolation; or, taking India as the base, 6-12 million tons (J. C. Olson, U.S.G.S., unpublished data). Using the relation between reserves and crustal abundance, world thorium resources would be expected to be of the order of 20 to 200 million tons (McKelvey, op. cit.). Low-grade resources have been little explored, but data from specific deposits show that their ratio to high-grade resources over the world may be similar to that in the United States and known examples indicate their large magnitude. Thus, the Kaffo riebeckite granite of Nigeria contains 70 tons of uranium, at least 140 tons of thorium, and about 1,840 tons of $(Nb,Ta)_2O_5$ per foot of depth and is only one of several known in Nigeria to be highly radioactive (R. A. Mackay and K. E. Beer, Geol. Survey of Great Britain Rept. 9SM (AED.95). Carbonatite averaging 0.07 percent ThO_2 at Araxa, Brazil contains 110,000 tons above a depth of 475 feet (D. Guimaraes, Div. de Fomento da Producao Mineral Belo Horizonte, Bull. 103) and carbonatites at Palabora in the Transvaal and in Kenya, averaging about 0.02-0.05 percent ThO_2, contain tonnages of the same order of magnitude at shallow depths. As with uranium, an extrapolation from the United States to the rest of the world on the basis of proportionality of areas -- 17.3 x 6 billion tons = about 100 billion tons (7 million Q)--probably supplies an estimate of potential resources valid as to general order of magnitude.

Lithium is not in great demand and hence its resources have been little explored. Li^6 in known minable deposits in the United States probably totals about 73,000 tons, with an energy equivalent of 21 Q (table 7). World minable reserves probably contain about 230,000 tons of Li^6, with an energy equivalent of 70 Q (table 8). Low-grade deposits are little known but should be of about the same magnitude as those of uranium. The Li^6 content of the ocean is 20 billion tons, with an energy equivalent of 6 million Q (table 8).

Water power, geothermal energy, and other energy sources

The installed capacity of water-power plants of the United States is about 38,600 megawatts, and the 1962 output was 168 million megawatt hours. The potential at mean flow is about 121,000 MW, equivalent to an annual production of 1 billion MW hours. The installed capacity over the world is about 180,000 MW, and the potential at the mean flow is about 2,700,000 MW (table 9).

According to D. E. White [U. S Geol. Survey, unpublished data], present world utilization of geothermal energy is in the order of 1,000 MW, and this can probably be increased 10-100 times for at least 50 years. Stored energy to a depth of 3 km that might be recoverable at or near present costs are estimated to be 0.12 Q. Of the total resources of geothermal energy, probably 5 to 10 percent occurs in the United States.

Other sources of energy include tidal power and various forms of solar energy, including direct radiation, wind power, and ocean heat. These are potentially enormous (for example, the solar radiation striking the earth's surface amounts to 3,200 Q per year, and of this 90 Q is converted into wind), but no estimates have been made of the fractions that might be recovered at various costs.

Conclusions

Known supplies of coal minable at or below present prices are more than adequate for foreseeable needs through the 20th century. Large additional resources exist, and if the research needed to advance technology is pressed, low cost supplies should be available for many more decades at prices comparable to those prevailing now. Proved reserves of oil and gas are sufficient for only a decade or so but substantial additional resources can be developed through continued exploration and improvement of secondary recovery practices. Resources of oil shale and related deposits are enormous.

Minable reserves of uranium are large and much larger tonnages in deposits of the same quality will be discovered on further exploration. At present low rates of reactor efficiency, the energy available from these sources is small, although it is ample to support a budding nuclear power industry for a few decades, provided the exploration for concealed deposits is pursued successfully.

If breeder technology is developed for commercial use, energy from U^{238} and Th will be available for millenia to come from low-grade resources--phosphorites, shales, and igneous rocks.

If control of fusion becomes economical, enormous energy resources will be available from lithium in relatively shallow parts of the earth's crust, and especially from lithium and deuterium in the ocean.

The contrast between the energy that is available in known sources available at present prices and established technology, and that potentially available through successful exploration and process development is almost staggering, and underscores the critical importance of research, exploration and development in meeting future needs.

Table 7. United States lithium reserves
(In short tons LiO_2. Estimated by J. J. Norton, U. S. Geological Survey)

Locality	Measured and indicated reserves: Major operating mines	Measured and indicated reserves: Other deposits	Inferred reserves
Foote Mineral Co. mine, Kings Mountain, N. C.	317,000	240,000	
Other deposits in the Kings Mountain district, N. C.	--	490,000	
Black Hills, S. Dak.	--	12,000	
Searles Lake, Calif.	--	90,000	
Total (rounded)		1,000,000	1,000,000 1/
Li^6 (energy equivalent in 10^{18} Btu in parenthesis)			73,000 (22)

1/ Mainly in the Kings Mountain district. Further exploration undoubtedly will reveal additional reserves of high-grade ore (the relation between reserves and abundance suggests that the tonnage of lithium may be at least 6 and perhaps 60 million tons, or 0.42-4.2 million tons of lithium-6; see McKelvey, op. cit.) and far larger tonnages of lithium-6 in various classes of resources are about the same as or slightly larger than those of uranium.

Table 8. World reserves of lithium[1/]
(In short tons LiO_2. Estimated by J. J. Norton, U. S. Geological Survey)

Area	Measured and indicated reserves	Inferred reserves
United States	1,000,000	1,000,000
Canada	400,000	2,000,000
Africa	200,000	2,000,000
	1,700,000	5,000,000
Li^6 (energy equivalent in 10^{18} Btu in parenthesis)	230,000 (70)	
Li^6 content of the ocean (energy equivalent in 10^{18} Btu)	20×10^9 (6,000,000)	

1/ Known world reserves of lithium are limited to a few areas; reserves at the four main producing localities -- Kings Mountain, N.C., Searles Lake, Calif.; Barraute, Quebec; and Bekita, southern Rhodesia -- account for the bulk of the 1.7 million tons of measured and indicated reserves of LiO_2. Unquestionably, the estimate of 6.7 million tons in deposits of minable quality is conservative. In addition, low grade deposits may be expected in about the same abundance as those of uranium.

Table 9. Installed capacity and potential waterpower of the United States and world[1/]
(In megawatts)

	Gross theoretical power, at 100 percent efficiency and flows			Developed sites	
	At flows available 95 percent of the time	At flows available 50 percent of the time	Mean flow	Number of sites	Installed capacity of waterpower plants
United States	33,800	72,000	121,300	1,398	38,600
World	--	--	2,724,000	--	180,900

1/ Based on estimates by L. L. Young, 1964, U. S. Geol. Survey Circ. 483.

THE ECONOMICS OF COAL SUPPLY

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Rapid changes in bituminous coal markets since the end of World War II, especially the loss of its two largest markets--space heating and railroad fuel--have compelled substantial adjustments in the industry. In 1947, the year of peak bituminous coal production in the United States, railroad consumption and retail deliveries, representing primarily residential and commercial space heating, had already fallen well below their earlier peaks; nevertheless, together they still accounted for 206 million tons or almost 40% of total bituminous coal consumption. The loss of the railroad market to diesel oil was especially rapid and by 1960 total railroad consumption of coal had declined to about 2 million tons and was by then so small that separate statistical tabulation was discontinued. Between 1947 and 1963 these two markets combined--railroads and retail deliveries--represented a loss of over 180 million tons and dropped to less than 6% of a total bituminous coal consumption that had declined by 25%. During this same period significant, although more moderate, losses were sustained in the industrial and coke markets.

The coal industry responded to this challenge to its survival with the rapid introduction of mechanization and improved technology that has helped to maintain its relative position as the dominant source of primary energy in the highly competitive and rapidly expanding electric energy market. Since 1947 the growth in coal consumption by electric utilities of 123 million tons has exceeded the loss in the railroad market. An increasing, although small, share of this growth in the electric energy market actually represents the indirect re-entry of coal into the space heating market.

Progress in coal mining technology began to accelerate in 1950 and between that year and 1963 has achieved an increase in productivity of almost 125% from 6.77 tons to 15.19 tons per man-day. This, in turn, has made possible in this period a reduction of over 9% in the mine price of coal despite an increase of 62% in coal miners' wages and a 33% rise in the general price level as measured by the Gross National Product price deflators. But improved technology and reduced prices at the mine have not been sufficient to maintain coal's competitive position. Lower transportation costs were also necessary.

For coal, more than for any other fuel, the cost of transportation represents a major element of delivered cost, in many cases amounting to more than half the total cost to the consumer. Until about five years ago the cost of rail transportation, which accounts for over 70% of all coal shipments, tended to increase and to offset reductions in the mine price of coal. However, during the past five years growing recognition by the railroads that unless they succeeded in reducing the cost of coal transportation they were threatened with the loss of their most important single source of freight revenue, has resulted in significant reductions in coal transportation costs. This recognition was helped considerably by the advent of the coal pipeline and, although only one such pipeline was actually built and even this one was finally shut down in response to a very large reduction in railroad freight rates, its availability as a potential competitor to rail transportation has had its effect on coal freight rates.

In the past three years particularly, railroad rate reductions have accounted for some important reductions in delivered coal costs. These rate reductions have been associated with large volume movements and have been the result in the main of changes in railroad management techniques and in rate-making that has given recognition to the economies of scale and the technological opportunities in trainload versus carload deliveries, although the contribution of technological changes has until now been by far the smaller element. The full benefits of technological improvement in rail transportation remain to be realized and offer the prospect of further substantial reductions in rail transportation cost.

The growing importance of the electric utility market to where it now accounts for over half of total bituminous coal consumption in the United States has significantly affected the coal industry's competitive environment. On the one hand coal must compete more intensively on a delivered cost per million Btu basis with alternative sources of energy. On the other hand, however, this has reduced the vulnerability of coal to shifts in consumer preference and the effect of the convenience factor in the choice of fuel, and it has also made possible more extensive exploitation of the economies of scale both in coal mining and in transportation.

In the case of fuels, perhaps more so than for any other natural resources, the opportunities for substitution among alternatives, especially for large-scale utilization of primary energy, are very high. The consumer of primary energy is not really interested in tons of coal, barrels of oil or cubic feet of gas. Ultimately the large consumer is concerned with purchasing the energy value represented by these particular forms of energy. The broader the range of opportunities for substitution among alternatives the stronger are the competitive forces affecting the market. While there may be some purposes for which it is not technologically feasible to substitute one energy source for another, several or all are effective substitutes for most purposes. In the two major areas of energy use where substitutes are not now entirely feasible technically--coke in the steelmaking process and motor fuel--they may both be vulnerable over the long run. The use of coke per ton of steel has been declining as a result of the use of techniques such as fuel injection, and direct steel reduction, if it should become feasible, would virtually eliminate the use of coke. The development of the electric automobile of course would have a major effect on the use of motor fuel and, indeed, would provide a means for coal to enter this market indirectly. If one allows for conversion of primary energy to secondary forms, almost all energy use is vulnerable to competitive substitution.

In the electric energy market coal must compete with the other fossil fuels, all of which can be converted to electric energy, and with nuclear power now emerging as a vigorous competitor for this market. Therefore, to maintain its competitive position, the coal industry must continue its efforts to provide the lowest delivered cost. While this imposes on the coal and transportation industries the need to exploit to the fullest imaginative technology and marketing, it offers at the same time the opportunity to exploit economies of scale.

The growth in the electric utility industry has led to very substantial increases in the size of generating units and plants and thus to a corresponding growth in the level of fuel consumption at a single location. A one million kilowatt generating plant, for example, consumes approximately 2-1/2 million tons of coal a year. This trend toward greater concentration in the size of individual consuming units has been paralleled by a trend toward greater concentration of coal reserves and production in larger size units. Since 1950 the proportion of total coal production accounted for by mines producing over 500,000 tons per year has risen from about 40% to almost 53% in 1963. This increased concentration of production is making possible more rational mining development and exploitation of the more advanced technology and mechanization that is available to yield higher productivity and lower price. Similarly, in transportation, railroad shipments of coal can be organized to take advantage of trainload movements at high speed and to utilize railroad capital equipment much more intensively. This has provided important opportunities for further cost reduction.

Despite the efforts of both the coal and transportation industries to reduce the delivered cost of coal and to maintain coal's competitiveness in fuel markets, there are institutional factors that may inhibit the ability of coal to compete either by absolute restrictions on coal use or by the imposition of cost increases that would seriously impair coal's competitive capabilities. One of these that may be of particular interest and offer a special challenge to chemists and chemical engineers is the increasingly widespread public concern over the problems of air pollution control.

Governmental regulations to alleviate air pollution could possibly prevent, or at least limit, the use of coal and distort the structure of fuel markets. Unfortunately, our knowledge of the effects of the products of combustion on living organisms is meager and regulation, in the absence of solidly based information, therefore, may tend to be excessively stringent. A well-known illustration of the effect of air pollution on fuel use is the situation in southern California. Despite indications that it would be possible to deliver coal in large quantities for electric generation in this area at a lower cost than presently prevailing fuel prices, air pollution control regulations prevent coal from entering this market at the present time.

Among the challenges confronting the coal industry, and the other fuel industries as well, is the need, first to determine the effects of the products of combustion on the environment, and then to find an economical means to eliminate those effects that are found to be harmful. There have been some efforts in this direction, including some technological developments to make possible the removal of sulphur prior to combustion. However, these have all involved processes that result in substantially higher costs for the heat content of the coal. Keeping in mind that coal, more so than any other fossil fuel, needs to compete in markets with very high substitution possibilities and therefore must give particularly strong emphasis to cost, it is clear that the search for techniques to control pollution, including the removal of pollutants prior to combustion, must be directed toward achieving this result without increasing the cost of its heat content. There are clear indications that for a long time the problem of controlling the effects of sulphur or its oxides at the level of vegetable, animal and human life can be adequately and economically taken care of by diffusion into the upper atmosphere, and by resorting for this purpose to high stacks currently in the 800-900 foot range, but eventually rising to 1,200 feet or even higher. Nevertheless, as a matter of challenge, research efforts directed toward removal of sulphur or other pollutants prior to combustion need to be continued, keeping in mind that increases in the cost of using coal would adversely affect coal's competitive position.

The emergence of nuclear power as the most serious competitor in coal's largest growth market lends added emphasis to the need for continued reductions in delivered coal costs. Nuclear electric generation has made substantial progress toward achieving competitiveness in the electric utility market and can be expected to exert increasingly intensive downward pressure on competitive fuel prices in this market over the next several years. This is especially significant for coal, but far less important at the present time to the other fossil fuels because electric generation represents a relatively small share of their total markets. Nevertheless, it will also become increasingly significant for the fossil fuels other than coal over the longer run as electric energy continues to make wider inroads over the entire range of energy use. Indeed, the competitive battle between coal and nuclear power can be expected to help make possible the lower electric energy costs which would stimulate those inroads.

The outlook for a keen competitive struggle between coal and nuclear power would indicate that, looking ahead for a number of years, we can expect little upward pressure on coal prices, and in many parts of the country where coal costs have been especially high further cost reductions can be anticipated. Current trends toward reducing those costs through lower costs of coal at the mine, and especially through lower transportation costs, can be expected to continue so that regional differences in coal costs are likely to be narrowed. The effectiveness of the coal industry's efforts to reduce its costs and the concomitant efforts of the transportation industry, especially the railroads, to reduce its costs will, in turn, exert strong competitive pressure on nuclear power and stimulate its technological progress toward lower costs, thus imposing a descending ceiling on coal prices.

The wide range of substitution capabilities among the several sources of energy, and most importantly the advent of nuclear power as a competitive source of energy in coal's largest market, can be expected to elicit the technical and economic responses from both the coal and transportation industries that will make possible a rising level of coal use without significant increases in real costs.

THE ECONOMICS OF OIL AND GAS SUPPLY

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I. Introduction: the economic concept of "supply"

The determinants of oil and gas supply are extremely complex, as mere recitation of some distinctive characteristics of the industry--and some equally distinctive governmental practices with respect to it--readily suggests. The complete production cycle, from initial exploration to exhaustion of deposits, is very long--often fifty years or more. Exploration and development, especially the former, are characterized by great uncertainty as to results. Absent regulation, expected future prices and costs are a major influence on current rates of extraction from developed reservoirs. Ownership of extracted oil and gas in the United States is governed basically by the "rule of capture," which, with multiple interests in a common reservoir, encourages rapid exploitation;[1] yet ultimate recovery from an oil reservoir is inversely related to the rapidity of exploitation. Largely for this reason, oil well densities and rates of extraction are regulated under conservation statutes in most producing states. Oil and gas are joint products and, to a limited degree, mutually competitive products. Apparently to provide relative encouragement to oil and gas production, income from these minerals is accorded differentially low federal tax rates by means of special depletion and other allowances. Oil imports into the United States are limited by a quota system. The wellhead price of natural gas destined for interstate transmission is subject to federal regulation, but there is no direct regulation of crude oil prices at any governmental level.

Within the limits of this short paper it is impossible to deal with the international aspects of oil and gas supply. It is necessary to confine the discussion to the domestic scene, and even then to proceed at a relatively high level of abstraction. It is all the more essential, therefore, that the concept of supply employed be quite clear from the outset.

"Supply" is a functional economic concept developed explicitly for use in the analysis of relative prices and the associated allocation of productive resources among competing uses. Functionally conceived, supply is not a given stock or rate of output of a good, but rather is a schedule of alternative quantities of a good that would be offered for sale during a specified time at various alternative prices. For reasons to be made clear below, the quantities in the supply schedule are nearly always positively related to price. The companion concept is "demand": a schedule of alternative quantities of a good that would be purchased during a specified time at various alternative prices (the quantities being negatively related to price). Supply and demand so conceived indicate for each good and time period a unique market-clearing price, hence the volume of sales that tends to be effected. Given demand, an increase in supply, i. e., an increase in the quantity offered at each price, decreases the market-clearing price and increases the volume of sales. A decrease in supply has the opposite effect, of course.

It should be readily apparent that the quantity of a good offered for sale at a given price depends in some sense upon the costs of making units of the good available for sale. In markets where there are many actual and potential sellers, so that no one can significantly affect the price through his separate offers, it is in the interest of any seller to offer a unit whenever the necessary increment to his total costs is less than the price.[2] It follows that the quantity offered by all sellers taken together is pushed to the point where the incremental cost of the last unit--the marginal cost--for each seller is equal to the price. Thus, supply is a function of marginal costs at alternative levels of output. With a given state of technology and over the usually relevant range of output, marginal costs tend to rise with increasing quantities offered for sale. This results from diminishing marginal productivity of variable inputs and the progressive addition of higher-cost facilities to make increasing quantities available. Consequently, with a given state of technology, it is only at increasing prices that increasing quantities are offered for sale. This is the reason why in the short run an increase in demand normally increases the market-clearing price.

The elasticity of supply is a measure of the degree to which quantities offered for sale respond to a change in price. If the response is small (supply inelastic), then a given change in demand causes a relatively large change in the market-clearing price and a relatively small change in the volume of sales effected. If the response is large (supply elastic), then the relative effects on price and sales volume are reversed.

As suggested by a qualifying phrase used above, the state of technology is a fundamental determinant of supply in any industry. A technological change which reduces marginal costs at all levels of output increases the quantity offered for sale at any given price; that is to say, it increases supply as defined. Given demand, such technological change decreases the market-clearing price and increases the volume of sales effected. Technological progress thus limits the increases in price necessary to induce increasing quantities of output over time; if rapid enough, it can permit increasing quantities of output over time at decreasing prices.

Quite aside from technological change, the characteristics of supply in any industry depend upon the time period specified as relevant to a given market problem. Since supply is a function of marginal costs, defined as the increments to total costs necessary to add successive units to the quantity available for sale, supply depends upon the types of costs that are variable during the specified period. In relatively short periods, during which productive facilities and related expenses may be regarded as fixed, only user costs[3] and such direct costs as labor and materials are variable. Within the technical capacity of the installed facilities, therefore, only such user and direct costs limit the different quantities of product made available for sale at different prices. Supply tends to be relatively inelastic; and if demand is sufficiently depressed, sales may willingly be made at prices below full costs per unit. In the long run, however, all costs are variable--including the costs of replacing and adding to facilities. Consequently, it is total costs that limit the quantities made available for sale at different prices in the long run. Long-run supply tends to be substantially more elastic than short-run supply, and the long-run market-clearing price always covers full costs per unit.

Following a brief general description of the oil and gas production cycle, we shall consider the characteristics of supply--and their implications--in the decision periods corresponding to different phases of that cycle.

II. The oil and gas production cycle

Oil and gas are found in underground formations of porous rock surrounded by impervious materials that trap the migratory minerals and confine them under pressure. Relative to the total volume of earth down to the depths now accessible to drillers, oil and gas bearing formations are neither large nor densely distributed, even in those major sedimentary basins where they are most concentrated. Bearing formations vary widely in size, depth, porosity, pressure and other economically relevant characteristics. The specific qualities of the minerals themselves also vary widely. Some gas is usually found present with oil, either as a "cap" or dissolved in the oil. In such cases, the pressurized gas is a valuable aid in forcing oil through the porous rock and into well bores. Gas also is often found alone or without significant association with oil. The degree and nature of the gas-oil association are not precisely predictable in advance of actual discovery in particular formations. Even nonassociated gas is most often found when the primary object of search is oil.

The exploration phase of the oil and gas production cycle begins with geological surveys to identify generally promising areas for more intensive investigation. These are followed by lease acquisitions, which are more or less expensive depending upon the supposed quality of the underlying prospects and the degree of competition among interested parties. The next step is geophysical testing,[4] such as by seismographic analysis, to locate beneath the surface specific geological formations capable of trapping oil and gas. If these tests yield poor results, leases may be abandoned without drilling; if they yield good results, exploration is completed with the drilling of one or more wells to the target formation. The uncertainty remaining after the typical amount of predrilling exploration is indicated by the fact that about nine out of ten exploratory wells are dry.

The development phase of the oil and gas production cycle begins with a discovery that is evaluated as worth the additional investment required to put it into production. Development consists of drilling appropriately spaced wells to the bearing formation and equipping these wells with flow regulators, pumps, storage tanks and gathering pipelines. The process incidentally involves discovery of the exact limitations of the producing formation and the operating characteristics--pressure, porosity, etc.--of the reservoir. When development is completed, dry holes mark the limits of the reservoir as well as anomalies within it. Some wells may be drilled for purposes of reinjecting gas or water and thereby maintaining reservoir pressure.

Outlays on exploration and development in the oil and gas industry are capital investments corresponding to plant and equipment expenditures in other industries. In recent years, domestic exploration and development outlays of the industry have exceeded $4 billion annually. Exploration accounts for about 40 percent of the total, development for the remaining 60 percent.[5]

The final phase of the production cycle is extraction. As a process, it is essentially continuous and largely automatic, the extractive force being pressure differential supplied either naturally or by means of pumps. Consequently, extraction costs typically are small in relation to exploration and development costs. Put another way, the great bulk of the charges to current income from extraction are indirect (and fixed) costs associated with exploratory and developmental capital outlays. Even the labor costs of operating a reservoir, chiefly for record-keeping and for general supervision and maintenance of the wells and their equipment, are in the main fixed over a wide range of output. Other than user costs, the principal variable costs are fuel costs and severance taxes.

III. <u>Supply in various decision periods</u>

We now consider the determinants of oil and gas supply in different decision periods. We begin with the shortest period, corresponding to the extraction phase, in which only a few costs are variable, and proceed in two steps to the longest period, corresponding to the exploration phase, in which all costs are variable. At each step in the analysis we shall attempt to indicate the supply characteristics that help explain the large extent of governmental interference with this industry.

A. <u>Supply in the extraction decision period</u>. Assume in operation a given number of oil and gas reservoirs of specified quality, these being the result of past exploratory and developmental effort. (The costs of such effort are sunk, of course.) At first, assume each reservoir to be operated by a number of competitive producers, without mutual agreement or public regulation. The decision before the several operators is the rate of extraction from each property at any point in time--and, by implication, the time-distribution of total recovery from each reservoir over its operating life.

In the interest of maximizing his income, each operator will at every point in time push the rate of extraction from his property to the point were marginal cost--the increment to total costs resulting from the last unit extracted--equals the going price. The relevant marginal cost is the sum of two components: marginal direct cost and marginal user cost. Marginal user cost for the individual competitive operator is, in turn, the sum of three components: marginal user cost of timing, marginal user cost of nonrecovery, and marginal user cost of competitive extraction.[6]

Marginal user cost of timing is the discounted present value of the net receipts (gross receipts less direct costs) sacrificed in future by extracting a unit now that might have been extracted at a later time. Given the total recoverable oil and gas in a reservoir, a unit produced now is a unit that cannot be produced later; a cost of producing a unit now therefore is the present value of the future income consequently sacrificed. Marginal user cost of nonrecovery stems from the fact that, at least beyond some critical point, ultimate recovery from an oil reservoir is inversely related to the rate of extraction per unit of time. (In general, this is not true of nonassociated gas reservoirs.) Thus marginal user cost of nonrecovery is the discounted present value of the net receipts sacrificed in future through additional nonrecovery resulting from a unit extracted now.

Marginal user cost of competitive extraction is of an entirely different nature. It stems from the "rule of capture," under which an operator is entitled to oil and gas produced through wells located entirely on his property, even though the minerals may have migrated underground from adjoining properties. Thus, marginal user cost of competitive extraction is the present value of the net receipts sacrificed to a neighbor as the result of extracting a unit now from one's own property. The cost is negative, of course. A unit extracted now is a unit that cannot be lost to a neighbor; a unit not extracted now is a unit potentially lost to a neighbor.

Marginal user costs obviously depend upon expected future prices and extraction costs. The higher are expected future prices and the lower are expected future costs of extraction, the larger is the present value of future net receipts sacrificed by extracting a unit now. Thus, for instance, the expectation of rising prices raises the marginal user costs of timing and of nonrecovery and reduces current supply, while the expectation of falling prices lowers the marginal user costs of timing and of nonrecovery and increases current supply.

To repeat, it maximizes the individual competitive operator's income if he pushes the rate of extraction from his property to the point where marginal cost equals price. But the negative component of marginal user cost--marginal user cost of competitive extraction--may entirely offset the positive components--marginal user costs of timing and of nonrecovery. If so, the rate of extraction is pushed to the point where only marginal direct cost equals price. There are two undesirable consequences of that. First, supply becomes quite inelastic, even at very low prices. Consequently, price is highly unstable in response to fluctuations in demand (as over the business cycle). Second, since the negative marginal user cost of competitive extraction is a purely artificial private cost, extraction is pushed to the point where the actual marginal cost of all operators exceeds the price. Thus, even if the market-clearing price yields a net income to operators collectively, that income is not maximized within the constraints of the opportunity. In effect, wastes are imposed upon the system of extraction, these taking the specific forms of improper distribution of extraction in time and loss of ultimate recovery. These imposed wastes reduce supply from each reservoir over its life as a whole.

There are two general approaches to removing or limiting the wastes caused by competitive extraction from common reservoirs. The first, and in principle most satisfactory of these, is to operate each reservoir as a unit, dividing the proceeds from extraction among the various leaseholders on the basis of some equitable formula. This approach simply removes the source of negative marginal user costs of competitive extraction and allows unit managers, on behalf of all leaseholders, to make extraction decisions on the basis of actual marginal costs. Marginal user costs of timing and of nonrecovery are in effect freed to perform their extraction-limiting function at any point in time, particularly when current prices tend to fall relative to expected future prices. Supply consequently is more elastic than under free competitive extraction. All producing states permit and even encourage voluntary unitization agreements, but only a few--and those not the principal producing states--provide any compulsion in unitizing oil and gas reservoirs.

The other approach--the one almost universally used in the United States--is to regulate production directly, assigning production quotas by wells to leaseholders. The total allowable production typically is limited by the smaller of (a) the sum of the reservoir extraction rates consistent with near-maximum ultimate recovery or (b) the total quantity demanded at the going price, whatever that may be.[7] Well quotas are based on relatively inflexible formulas in which well density and depth are the usual arguments. The quota formulas usually encourage dense well drilling to maximize leasehold allowables, so it is necessary to regulate well-spacing also. This approach looks not to removing the source of negative marginal user costs of competitive extraction, but rather to controlling operators' responses to such costs by means of detailed regulation. The administrative necessity of relying upon formulas prevents the flexible adjustment of marginal cost to price required for continuous income maximization. The system generally eliminates wastes of nonrecovery, but students of the industry are agreed that it stimulates excessive drilling and overcapacity.[8] The wastes it permits, while far less than those of free competitive extraction, significantly reduce supply from each reservoir over its life as a whole.

In the extraction decision period, the special income tax allowances for oil and gas have little or no effect on supply under either unitization or regulation approaching the conditions of unitization. The reason is that the allowances have roughly offsetting effects on current net receipts and marginal user costs. Under free competitive extraction, with marginal user costs depressed perhaps to zero because of the negative component in them, the special allowances encourage excessively rapid exploitation and reduce supply from each reservoir over its life as a whole.

B. Supply in the development decision period. Assume now a given number of undeveloped oil and gas discoveries of specified quality, these being the result of past exploratory effort. (The costs of the exploratory effort are sunk, of course.) The decision before the several operators is the rate of investment in development wells and equipment with a view to making new extractive capacity available. In effect, the decision determines the supply of developed reservoirs, which supply becomes the principal basis of oil and gas supply in the extraction decision period.

Again with a view to maximizing his income (or rather the present worth of it), each operator will push development investment to the point where the present value of the expected increment to net receipts from the last investment is just equal to the associated increment to total investment outlays. In forming estimates of incremental net receipts, the operator must consider total recoverable oil and gas in each reservoir, the nature of the gas-oil combination, the probable time-distribution of recovery, the associated degree of avoidable nonrecovery, and the probable time-path of prices and extraction costs over the operating life of the reservoir. The necessary increment to total investment outlays is affected by depth and similar influences on drilling costs, accessibility of drilling sites, and the number of wells consistent with the probable time-distribution of recovery.

Other factors being the same, the higher the expected level of oil and gas prices, the lower the quality of discovery it is economical to develop. Thus, the elasticity of supply in the development decision period reflects the qualitative distribution of discoveries made through exploration. No discovery will be developed unless the expected price will cover expected extraction costs plus development costs, while an already developed reservoir will be operated if the price covers no more than extraction costs. Consequently, the elasticity of supply in the development decision period is greater than that in the extraction decision period.

The general level of supply--the size of the quantities made available at different prices--in the development decision period varies directly with the efficiency of extraction expected. Under free competitive extraction, avoidable nonrecovery of oil and gas and the number of wells each operator must drill both are large relative to the situation under unitized operation of reservoirs. Consequently, given the quality of discoveries available for development, the number it is economical to develop at each expected price level is smaller under free competitive extraction than under unitization; which is to say, supply is smaller under free competitive extraction than under unitization. For similar reasons, but to a lesser degree, supply is smaller under the prevailing system of detailed production regulation than under unitization.

The special income tax allowances for oil and gas have a significant effect on supply in the development decision period. Relative to a situation of equal taxation of income from all sources, they increase the net receipts from extraction at any given price level and thus increase the number of discoveries it is economical to develop at each expected price level.[9] In short, they increase supply in this period.

C. Supply in the exploration decision period. At the outset of the exploration decision period, operators are confronted with an array of general prospects of various supposed qualities. Knowledge of these prospects is generally available; no significant costs are sunk at the beginning of the decision period. The decision before operators is the rate of investment in exploration with a view to making new discoveries available for development.

As with development, each operator will push exploratory investment to the point where the present value of the expected increment to net receipts from the last investment is just equal to the associated increment to total investment outlays. The factors relevant to expected net receipts from exploration are the same as those in the development decision, except that expected development outlays enter as additional negative arguments. The necessary increment to investment outlays reflects accessibility of prospects, depth of promising formations and the difficulty of drilling through intervening formations.

The elasticity of supply in the exploration decision period reflects the qualitative distribution of available prospects. Since no prospect will be fully explored unless the expected price of oil and gas will cover expected exploration plus development plus extraction costs, while an already discovered deposit will be developed if the expected price will cover only expected development plus extraction costs, the elasticity of supply in the exploration decision period is greater than that in the development decision period. Whatever the level of demand in this longest of decision periods, the market-clearing price covers full costs of the complete production cycle.

For reasons identical with those given in the discussion of the development decision period, supply in the exploration decision period is reduced by the wastes of free competitive extraction and detailed production regulation relative to unitized operation of reservoirs; and is increased by the special income tax allowances relative to a situation of equal taxation of income from all sources.

IV. The price of oil and gas in the very long run

As a country such as the United States continues to use domestically produced oil and gas in large--even increasing--amounts, at some point the quality of remaining exploratory prospects inevitably begins to decline. Oil and gas must be searched for in less accessible places, at greater depths, in leaner deposits. The long-run supply thus tends to decline, and the market-clearing price tends to rise.

We have long since passed the point of declining quality of prospects and have thus far averted rising relative prices only through continued progress in the technology of finding and extracting oil and gas and gradual reduction of the wastes of competitive extraction.

Today, the price of crude oil in the United States would not be nearly as high as it is were it not insulated from foreign competition; and the volume of production would not be as great as it is at that price were it not for the special income tax allowances. The price is no higher than it is at least partly because at slightly higher prices shale oil would make significant competitive inroads into crude oil markets. The price of domestically produced gas is freer of threats from foreign sources and substitutes but, assuming the regulatory authorities will continue to permit increases over time, it will not always be. Under these circumstances, the primary issue raised by the long-run supply of oil and gas is not the course of prices and the availability of fuels, but rather the survival of the oil and gas industry as we know it. If supply decreases with deteriorating exploratory prospects, the industry must shrink accordingly.

There are two lines of escape. First, the industry and its legislative friends can accelerate improvements in the regulatory system, moving ideally toward universal unitization of reservoirs and relaxation of detailed formula regulations. The potential cost reductions in this area may be as much as one-third the going price. Second, the industry can devote still more effort to technological improvements. The areas offering the greatest scope for improvement are predrilling exploration technique, drilling technique and recovery of oil in place. The progress already made in these areas gives reason for hope that the price of oil and gas may actually decline, and the industry may renew its growth, in the decades immediately ahead.

FOOTNOTES

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1. Under the "rule of capture," an operator is entitled to oil or gas produced through wells located entirely on his property, even though the minerals may have migrated in response to gravity or pressure differential in the natural reservoir from the property of others. The rule, if unmodified by mutual agreement or regulation, obviously provides incentive for rapid, competitive exploitation of a common reservoir by multiple leaseholders.

2. The condition of many actual and potential sellers prevails in the oil and gas industry. Accordingly, for purposes of this paper we ignore the characteristics of supply in industries where this condition is absent.

3. User costs reflect consumption of capital resulting from use, as distinguished from mere passage of time.

4. Depending upon the exact situation, some geophysical testing may occur in advance of leasing.

5. American Petroleum Institute, Independent Petroleum Assn. of America, Mid-Continent Oil and Gas Assn., Joint Association Survey, 1960 (Dec. 1962). The Survey indicates that exploration costs are close to one-half of total exploration and development outlays. However, the Survey's cost classification scheme assigns all dry hole costs to exploration, even though about one-half of all dry holes are drilled in developing proven discoveries.

6. The user cost terminology is based on Paul Davidson, "Public Policy Problems of the Domestic Crude Oil Industry," American Economic Review, March 1963, pp. 91-96.

7. This obviously leaves the market-clearing price indeterminate. Presumably it is set by some price leader on the basis of average cost plus target profit. Ironically, average cost varies inversely with the volume of output permitted.

8. For a more detailed discussion of these wastes, see James W. McKie and Stephen L. McDonald, "Petroleum Conservation in Theory and Practice," Quarterly Journal of Economics, February 1962, pp. 98-121.

9. This is not to say that the allowances increase the number of discoveries it is economical to develop relative to a situation of no income taxes at all. For detailed discussion of the effects of the allowances, see Stephen L. McDonald, Federal Tax Treatment of Income from Oil and Gas (Washington: The Brookings Institution, 1963).

ECONOMIC ASPECTS OF UNCONVENTIONAL ENERGY RESOURCES

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The two most important unconventional energy resources today are atomic energy and solar energy. Importance is here judged by the ability of these two energy resources to shoulder important parts of the world's energy load before the end of the present century. It is also influenced by a lack of resource restrictions for the indefinite future in the case of solar energy and a comparative lack of resource restrictions in the case of atomic energy if, as and when the breeding of nuclear fuels becomes economically attractive. But this judgment of high promise in the case of atomic energy remains qualified, as we shall note, by problems of disposing of the large quantities of nuclear waste materials that would be created by extensive nuclear power generation.

The unconventional energy resources abound, but are either inherently limited in possible significance or unproven economically to the best knowledge of the author. In the first group are wind and geothermal energy. For specific locations, geothermal energy has been of considerable value, but current commercial output is even now only about 1,000 megawatts electrical (MW), with about as much again in the form of known reserves.[1] The prospects for utilization of wind power are similarly limited. After careful study, Putnam gives wind power a potential approximately one-fifth that of hydroelectric power in the world's energy economy,[2] which in turn seems destined to supply only one or two per cent of the world's energy load for the foreseeable future.[3] Putnam's analysis was heavily influenced by his requirements for constancy of wind speed, which might not be as important if low cost storage becomes available. In the second category are a variety of devices of unknown potential, including fuel cells, controlled biological photosynthesis of fixed carbon in alga and others. By definition, these are beyond the scope of the present analysis (and its author).

Nuclear Power

Economic analyses of the prospects for nuclear power have been dominated within the past year by the decision of an electric utility, Jersey Central Power and Light Company, to build a nuclear plant, the Oyster Creek Nuclear Electric Generating Station, to produce electric power at a cost in the range of 4 mills per kilowatt-hour (kwhr).[4] This cost is below that which the Atomic Energy Commission (AEC) had predicted likely by 1970-75 in its 1962 "Report to the President."[5] The turn of events naturally has attracted considerable attention and will be used here as a starting point for appraisal of the economics of nuclear power. The central question pursued in the following paragraphs is whether Jersey Central's calculations reflect the true cost of nuclear electric power today. It will be found that they come close to doing so, but that for a society-wide evaluation of the portend of nuclear power, somewhat higher costs should be used. The latter are supplied and their implications for the further adoption of nuclear technologies suggested.

Cost Determinants

There are five important economic variables that determine the relative costs of nuclear power and conventional fossil fuel generated power in any given situation. These are:

1. Annual fixed charge on capital
2. Use factor (defined as ratio of kwhr actually generated over plant lifetime to product: plant capacity x lifetime hours in service)
3. Size of plant
4. Level of fuel cost
5. Public policy

The first two variables are important because nuclear power is more capital intensive than conventional power, i.e., for a given level of output, a larger proportion of nuclear power costs are in the form of capital expenses than is the case for conventional power. Thus, a low annual fixed charge and a high use factor both favor nuclear power and the converse of both favor fossil fuel power. The third variable derives its importance from the fact that nuclear power costs are reduced proportionately more by increasing plant size than are conventional power costs. The larger the plant, the more favorable are the per kwhr costs for nuclear power.

The level of fossil fuel cost is influenced in important degree by transportation expenses. Thus, the range in fuel cost in the United States is from 8 cents per million BTU in Texas to over 40 cents per million BTU in parts of New England and the Far West.[6] In contrast, nuclear fuel is for all practical purposes weightless per unit energy content. One pound of nuclear fuel is the equivalent of 1300 tons of coal. To the extent that nuclear power comes into use at competitive cost levels in the United States, it will tend to even out the geographic cost structure of electricity, though improvements in the technology of long distance power transmission are already working in this direction.

Finally, there is the effect of public policies. AEC has helped finance a large number of high cost nuclear power stations as a way of advancing power technologies,[7] and there is every reason to expect these policies will continue. The costs of the plants and the power they produce must be charged against technological progress, including the development of converter and breeder reactors. The same must be said of various public aids to large nuclear plants now on the line but embodying earlier versions of technologies now becoming competitive.[8] To the extent that public costs are incurred for nuclear power stations, these are part of the total costs that must be counted on a social balance sheet for the evaluation of nuclear power.

Oyster Creek Plant

Table 1 summarizes the comparison of fossil fuel and nuclear power costs made by Jersey Central. Three alternatives were considered: (1) a mine-mouth coal-fired plant in western Pennsylvania which would feed electricity into the GPU system[9] through additional high voltage transmission lines; (2) a coal-fired plant at the Oyster Creek site; and (3) the Oyster Creek nuclear plant. All production costs have been reduced to annual equivalents.[10] The figures reported by Jersey Central were for blocks of years by plant age: 1-5 years, 6-10 years, 11-20 years and 21-30 years. Annual costs were different in each block of years, due especially to a variation in expected fuel cycle costs. In reducing the Jersey Central figures to annual equivalents, the reported costs for each block of years were multiplied by their present worth factors and the sum of all such weighted costs were divided by the present worth factor for the entire 30 year period.

The three different capacities listed for the Oyster Creek Nuclear Plant reflect an expected "stretch-out" in capacity after the plant gets into operation. General Electric, the supplier of the nuclear plant, has set a guaranteed capacity of 565 KW but anticipates that "stretch-out" will be realized. Jersey Central plans for the 620 KW "stretch-out", but even with a "stretch-out" to 565 KW, the figures in Table 1 give the edge to the nuclear plant. It is interesting also to note from Table 1 the advantage of the Western Pennsylvania over the Oyster Creek Fossil Fuel plant, attesting to the low costs of long distance power transmission today. As a result, a plant located at the mine mouth can take advantage of the lower costs of shipping electricity rather than coal.

TABLE 1

Jersey Central Power and Light Company
Cost Comparisons for Oyster Creek Plant
(lifetime annual equivalent costs, mills/kwhr)

	Fossil Fuel Plants (600 MW)		Oyster Creek Nuclear Plant		
	Western Pa.	Oyster Creek	515MW	565MW	620MW
Plant cost, $/KW[a]	105	110	132	120	100
Fossil fuel cost per 10^6 BTU	17¢	26¢			
Fixed charges, mills/kwhr[b]					
Plant and other working capital	1.771	1.449	1.770	1.613	1.474
Fuel working capital	0.033	0.047	0.348	0.326	0.294
Fuel expense	1.599	2.301	1.384	1.371	1.365
Other operation and maintenance	0.493	0.405	0.594	0.551	0.516
Total[c]	3.897	4.203	4.096	3.861	3.650

[a] Transmission costs are included in fixed plant costs.

[b] Annual equivalent costs are the weighted average of age-related costs reported by Jersey Central. Weighting was made using present worth factors. Jersey Central used a 10.39% fixed charge on capital, straight line depreciation expected life of 30 years in all plants and 40 years on transmission facilities. Lifetime load factors were assumed identical for all plants at 83 percent, but the load factor calculation for the fossil fuel plants was made using an "equivalent system" technique. See Report, pp. 13-14.

[c] Minor differences between totals and sums of corresponding figures are due to rounding.

Source: Jersey Central Power and Light Company, Report on Economic Analysis for Oyster Creek Nuclear Electric Generating Station (February 17, 1964), Tables 1, 2, 3 as modified by footnote b, above.

The relevance of the Jersey Central results for a nation-wide evaluation of nuclear power depends on a number of considerations, including at least three points that have been raised in public discussion: (1) the appropriate annual fixed charge; (2) the prospects for "stretch-out"; and (3) whether the bid price by the General Electric Company for the nuclear portions of the Oyster Creek plant represents true costs to GE (at some assumed volume of production of similar plants), or whether, as some have argued, GE bid too low for the plant costs to be considered typical.[11]

It is unavoidably true that Jersey Central used methods of determining required revenue for fixed charges that reflect rate making practices in the state of New Jersey and the financial structure of the utility itself (although the latter was simplified for the sake of the public report). It is another matter, however, to develop figures for a national comparison. Using average state and federal taxes, average cost of capital and other representative conditions, the Federal Power Commission recommends a figure of 13.9 per cent fixed charge on capital in making comparisons of production costs.[12] For the purpose at hand, this figure will be rounded down to 13.5 per cent to reflect the 1964 federal corporation income tax reduction combined with omission of insurance charges. This is significantly higher than the 10.39 per cent used by Jersey Central. Insurance charges are treated separately since they are very different for the nuclear and conventional plants.

The evidence regarding "stretch-out" is inconclusive. Philip Sporn, a respected spokesman for the electric utility industry, has estimated that ten per cent is the most likely "stretch-out."[13] A General Electric spokesman predicts that the future trend will be toward design and cost estimates with less than 20 per cent stretch.[14] In the absence of more conclusive information, the 10 per cent figure is here judged safest to use for nuclear power cost comparisons.

The General Electric Company is probably the best authority for the question of future contract prices involving the GE boiling water reactor. The prices and policies published by GE on September 21, 1964 form the basis for data that will be used to represent the nuclear power potential in Table 2. The GE costs are slightly higher than those for the Oyster Creek plant, but the difference is not great.

Cost Comparison of Nuclear and Conventional Power

The various refinements indicated above have been incorporated in Table 2 to give a general comparison of nuclear with coal-fired technology in the large central station plants here discussed. Some differences remain in nuclear fuel and other operating expenses; therefore two sets of estimates are given for these. It will be noted that the Sporn and GE estimates (both of which have been modified by the present author, as indicated in Table 2) are in good agreement. Their greatest difference is in cost of insurance. On this point, the Sporn total of insurance plus operation and maintenance costs is closer to that of the Oyster Creek plant than is the corresponding GE total.[15] Coal-fired plants are represented by Mr. Sporn's Cardinal plant technology, the most advanced under construction today.

The most important message conveyed by Table 2 is that nuclear power plants can be built today at a lower cost to electric utilities than the best coal-fired plants in regions of moderate to high fossil fuel cost. Moreover, the progress in nuclear technology that has led to this result is sufficiently impressive to give credence to claims of expected continued downward trends in fuel costs,[16] which will in turn further reduce nuclear fuel operating expenses.

Social Costs

The question immediately arises as to whether all costs of nuclear power are represented in Tables 1 and 2. Insofar as taxes are concerned, no differentiation can be made between nuclear and conventional power since the FPC rate of 13.5 per cent was used for both. There are, however, three AEC policies that help defray costs of nuclear power: (1) design assistance; (2) waiver of fuel use charge for first five years of operation; and (3) price supports for byproduct plutonium production.

TABLE 2

GENERAL COST COMPARISON OF NUCLEAR AND COAL-FIRED PLANT TECHNOLOGIES

(lifetime annual equivalent costs, mills/kwhr)

	Coal-Fired Unit (Cardinal-type plant)			Nuclear Unit (Boiling Water Reactor)	
Capacity, megawatts	615			600	
Unit capital cost, $/KW	107			126[a]	
	Coal costs per 10^6 BTU				
	20¢	25¢	30¢	Sporn estimates	GE estimates
Fixed charges					
Plant[b]	2.07[b]	2.07[b]	2.07[b]	2.43[b]	2.43[b]
Fuel working capital[c]	0.03[c]	0.04[c]	0.05[c]	0.33[c]	0.33[c]
Fuel expense	1.73	2.16	2.60	1.45[d]	1.51[e]
Operation and maintenance	0.30	0.30	0.30	0.35	0.31
Insurance	neg.[f]	neg.[f]	neg.[f]	0.20	0.08
Total	4.13	4.57	5.02	4.76	4.66

[a] Estimated plant costs at $121. per installed kilowatt by interpolation of informa-formation supplied by GE, increased by 15 percent to allow for construction, interest, land and related cost as in Stathakis (see source of this table) to give $139. per kilowatt, which was divided by 1.10 to allow for ten percent stretch-out, giving the resulting $126. per kilowatt.

[b] Based on 13.5 percent fixed charge, 80 percent load factor.

[c] Obtained from Table 1 supra. Fuel working capital costs were omitted in all original estimates. It will be noted that the fuel working capital costs used in Table 2 were based on fixed charges of 10.39 percent as opposed to 13.5 percent used in the remainder of this table. No correction has been made for this difference because of the complexities of imputing fuel costs at different periods of time. The understatement in turn aids nuclear power more than conventional power.

[d] Equivalent annual fuel expense obtained by Sporn apparently using weighted average lifetime value obtained by present worth factors.

[e] For representative "equilibrium core" as described by Strathakis (see source of this table).

[f] Insurance on conventional plants is calculated using the Federal Power Commission recommended rate of 0.25 percent for each kilowatt of capacity investment.

Source: Coal-fired unit and Sporn estimates of nuclear unit are from Philip Sporn, "A Post-Oyster Creek Evaluation of the Current Status of Nuclear Electric Generation", Joint Committee on Atomic Energy, 88th Congress, 2nd Session, Nuclear Power Economics - Analysis and Comments - 1964,(Washington, D.C., 1964), Table 4 except as modified by footnotes above.

GE estimates are from G. J.Strathakis, "Nuclear Power Drives Energy Costs Down", Electrical World (October 5, 1964) except as modified by footnotes above.

These three are available for large central stations of the type here under discussion.

Design costs may or may not be large, depending on whether research and development is necessary for any parts of the system. If so, AEC is willing to finance the research and development costs[17] and this part of the expense must be regarded as a subsidy in the interest of progress, as noted in previous discussion. The Oyster Creek plant was not designed at AEC expense, nor did it utilize design concepts that necessitated R&D programs. Hence the figures shown in Table 1 include design expenses, but for a plant whose basic technology had been previously established. Table 2 is based on the same nuclear technology.

The waiver of fuel use charge does not greatly affect the previous calculations. The use charge represents interest on fuel inventory owned by AEC but used by the electric utility. With present AEC policies, Jersey Central estimated that the use charge adds $11 to $13 per kilowatt to the cost of the Oyster Creek plant. Jersey Central did not take advantage of the waiver in its calculations, but if it had done so, the effect would have been to reduce lifetime annual equivalent costs by about 0.06 mills/kwhr in the 10 per cent "stretch-out" (565 KW) plant. AEC has now recommended that legal requirements be changed to permit private ownership of special nuclear materials.[18] Jersey Central calculates that private ownership of fissionable fuels would in its case result in a capital expense of $22 to $30 per kilowatt. The calculations for the Oyster Creek plant assume that private ownership of nuclear fuels will, in fact, commence on July 1, 1973 and the fuel working capital cost reflects this assumption. If private ownership were to exist from the time of initial operation of the Oyster Creek plant, the costs would be about 0.04 mills/kwhr higher for the 10 per cent "stretch-out" (565 KW) plant.[19] Again, the effect of public policy is small enough that no important changes need be made in preceding conclusions.

With respect to plutonium buy-back, AEC has estimated that its current price of $10.00 per gram for plutonium isotopes 239 and 241 in nitrate form represents what the free market price will be in the near future,[20] i.e., before breeder reactors are in commercial use. Insofar as power applications are concerned, this is the economically correct objective and the author is in no position to question the numerical value set by AEC.[21] Jersey Central states that in its calculations, "the total plutonium credit averages less than 0.25 mills/kwhr." Thus, it would take a considerable change in the plutonium buy-back price to affect the competitive status of nuclear power and any future change is more likely to be upward than downward (because of the future possibility of using plutonium reactors for power), which will reduce the cost of nuclear power in today's reactors.

Finally, there is the possibility of social costs in the form of radioactive wastes. These costs are different from any thus far considered in that they will never be encountered in the market place except to the extent that public regulations require methods of radioactive control for which private firms must pay. The prospects for safe waste disposal are not reassuring when account is taken of the large volume of wastes that would be produced by widespread installation of nuclear power. AEC discussed methods of safe disposal in its 1962 "Report to the President" with the clear inference that environmental investigations had not yet reached the point at which reasonable technical criteria had been established for safe disposal of very low radioactive effluents into the environment.[22] AEC also discussed the disposal of high level wastes in its 1962 "Report to the President" indicating in that discussion that "aside from the central reactor development program proper, no other phase of the entire (civilian reactor) program is more important than that of waste disposal."[23] At the same time, AEC indicated that plans for ultimate high level waste disposal were still in the research stage.[24]

Until a safe program is designed to handle ultimate storage of high level wastes in large volume and until environmental standards are established which will prevent undue environmental concentrations of radioactive materials, the author cannot look with equanimity on the expansion of nuclear power generating capacity. If the costs of radioactivity controls increase the costs of nuclear power, then this is as it should be. Those who pay for the power must also pay for the control of any unwanted byproducts. We as a nation have an unenviable history of pollution control. Now, we are talking about pollutants that last decades, centuries in some cases. It is asking very little to decide how we shall live with the volume of radioactive waste materials in prospect before we set out on a course that presupposes their creation.

System Costs

On the assumption that nuclear power costs are fully established to include all social costs of power production, certain observations can be made on the integration of nuclear power in conventional electrical grids.

First, it will be recalled that the data in Tables 1 and 2 are for 600 MW plants. These are large central station plants. At one-tenth the size of the nuclear plant on which Table 2 is based, Strathakis reports over 2 times the cost he estimates for the Table 2 plant.[25] In contrast, Barzel gives results for conventional steam plants which indicate a 48 per cent increase in per kwhr costs as a result of a tenfold reduction in plant size.[26] The inference is that there is a size threshhold above which nuclear power has the cost advantage and below which conventional power has the cost advantage. The size of electric power generating stations depends on a compromise between market density and costs of transmission, to name only the most important variables.[27]

Just as there is a size distribution, so is there a use factor distribution among electric power stations. It will be recalled that high lifetime use factors were employed in Tables 1 and 2 (83 per cent and 80 per cent, respectively). As previously noted, high use factors favor the capital-intensive technology by spreading fixed costs over a larger output. The typical distribution of use factors among electric power stations in a given system is a compromise between age distribution of plants and their operating expenses in the light of the costs of power transmission. Operating expenses are typically highest in the oldest plants; so as plant age increases, it is customary to use the plant a smaller proportion of the time. At the extreme are peaking plants designed for very low load factors using technologies that are least capital intensive and most fuel intensive.

Now, the nuclear power plants that are installed first in any given system can truly be expected to have the highest use factors over their lifetimes. The reason is that they will have lower operating expenses for the same total cost of power than will the conventional plants. Thus, Jersey Central actually expects to realize an 83 per cent use factor with its Oyster Creek plant, but would only expect use factors in the range of 60 per cent with the fossil fuel alternatives[28] (although they were compared at the 83 per cent level). Later calculations for the introduction of nuclear power in the same system, however, will eventually run into more adverse lifetime use factors. There is only so much base load that can be carried in any given system. It is electric power demand that determines the total system output requirements. Eventually, prospective nuclear power additions will be considered in competition with less capital intensive technologies and for lower use factors. Just as there is a need for peaking plants today, so will there be a need for less capital intensive technologies among power plants in the systems of tomorrow.

An approximate indication of the prospects for introducing nuclear energy in today's electric power systems can be found by noting the incidence of large plants in the high and moderate cost fossil fuel areas. The geographic incidence of capacity by fossil fuel cost areas is shown in Table 3 and by plant size in Table 4. Referring to Table 3, it appears that about half of the nation's thermal generating capacity is in the cost range in which an advantage is shown for nuclear power at the 600 MW size level (compare Table 2) if we ignore possible cost differences that might result from different environmental health standards. From Table 4, we note that the number of power plants of large size is relatively limited. There is a tendency, however, for large plant size to be more important in the first, second and eighth FPC regions,

TABLE 3

THOUSANDS OF ELECTRICAL MEGAWATTS OF INSTALLED CAPACITY, 1960

FPC region[a]	Hydro	Fossil fuel								
		Cents per million BTU						Total[b]	Average fuel cost, cents per million BTU	
		Below 20	20 to 25	25 to 30	30 to 35	35 to 40	40 and over		1960 actual	1970 estimated[c]
I	3.9	0.9	0.9	0.5	9.7	13.0	0.1	25.1	33.6	35
II	0.6	8.4	8.3	6.0	5.6	0.0		28.3	22.8	24
III	6.6	4.4	5.7	6.6	3.6	1.4		21.8	24.8	28
IV	1.1	1.3	4.3	7.0	2.6	0.8		16.0	26.2	27
V	1.1	11.9	3.1	1.0	0.1			16.0	17.5	20
VI	1.5	0.2	0.8	0.2	0.1	0.1		1.4	23.8	24
VII	12.2		0.4	0.0	0.1			0.5	23.4	19
VIII	5.5				9.4	0.5	0.1	9.9	33.0	32
Total[b]	32.4	27.0	23.5	21.4	31.2	15.9	0.2	119.1	26.1	

a For an approximate geographic distribution of FPC regions, see state listings in Table 4, supra.

b Totals may differ slightly from the sum of numbers totaled because of rounding.

c Estimated costs for 1970 constructed by Edison Electric Institute.

Source: "Cooperative Power Reactor Demonstration Program, 1963", Hearings before the Subcommittee on Legislation of the Joint Committee on Atomic Energy, 88th Congress, 1st Session (July 9, August 7 and October 15, 1963), pp.23 and 24.

TABLE 4

FREQUENCY DISTRIBUTION OF STEAM-ELECTRIC PLANT SIZE, BY APPROXIMATE FEDERAL POWER COMMISSION REGIONS[a]

Plant Capacity MW[b]	I Connecticutt Delaware District of Columbia Maine Maryland Massachusetts New Hampshire New Jersey New York Pennsylvania Rhode Island Vermont	II Indiana Kentucky Michigan Ohio W. Virginia	III Alabama Florida Georgia N. Carolina S. Carolina Tennessee Virginia	IV Illinois Iowa Minnesota Missouri Wisconsin	V Arkansas Kansas Louisiana Mississippi New Mexico Oklahoma Texas	VI Colorado Nebraska N. Dakota S. Dakota Wyoming	VII Idaho Montana Oregon Utah Washington	VIII Arizona California Nevada
0 - 10	18	8	1	20	15	19	8	4
10 - 25	20	6	1	29	11	14	4	1
25 - 60	18	8	8	13	17	2	2	2
60 - 100	14	8	7	12	22	2	6	6
100 - 200	38	11	15	18	29	2	3	8
200 - 300	21	14	12	15	15	1	0	5
300 - 400	20	9	7	8	17	0	0	4
400 - 500	8	9	8	4	2	1	0	2
500 - 750	13	16	4	6	2	0	0	4
750 -1000	4	5	0	1	1	0	0	2
1000 & over	1	4	2	1	0	0	0	1

[a] States have been classified in FPC regions in which the largest proportion of their populations reside in those cases where FPC region boundary cuts through a state.

[b] Lower limit of each capacity range is to be interpreted as having capacities above the indicated levels. Thus a plant of 10.000 MW capacity belongs in the first group; a plant of 10.001 capacity, in the second.

Source: Tabulated from Federal Power Commission, Statistics of Electric Utilities in the United States, Privately Owned, (1962) Section VII.

where fossil fuel costs are higher (compare Table 3). It is clear that the existing geographic structure of conventional fuel costs and size structure of existing power systems permit considerable scope for introduction of nuclear power plants. A more exact conclusion would require considerably deeper analysis, including size and cost trends for both nuclear and conventional plants, which depend not only on plant technological developments, but also on regional fuel cost changes (see last column of Table 3), density of markets for future power, trends in transmission costs and others.[29]

Locational and Aggregative Economic Effects

The effects of reduced electric power costs on different industries in the United States were intensively studied by Schurr and Marschak over a decade ago.[30] Their work is still relevant for this special topic. The lower level of power costs considered in the Schurr-Marschak analysis was 4.0 mills/kwhr, a value which appears from Table 2 within the range of coal fired as well as nuclear powered plants, but the former only for certain regions, not for the broad range of localities where nuclear power might be available.

It would be impossible in a summary to do justice to Schurr and Marschak's findings; moreover, there is the possibility that new process technologies in the industries analyzed could cause some amendments of the details. It is informative, however, to note the three classes of economic effects considered in their study: (1) cost reduction in heavy energy consuming industries, assuming no important changes in process technologies; (2) cost reductions and changes in process technologies that might result from lower energy costs; (3) possible changes in the location of manufacturing establishments as a result of lower cost energy. Only a limited number of industries consumed, or offered sufficient prospects of consuming, enough energy (in proportion to all other costs) to be considered in the analysis. These were: aluminum; chlorine and caustic soda; phosphate fertilizers; cement; brick; flat glass; iron and steel; and rail transportation. Some of these showed sensitivity to energy cost changes if carried to the 4.0 mills/kwhr level. Others did not. We can generalize to the extent of noting that in individual cases and where no process shift was involved, the production of a commodity having ubiquitous inputs or a commodity with no important weight losses between inputs and outputs might become market oriented as the result of lower power costs in the vicinity of consumption centers. The opposite possibility exists where reduced power costs at raw materials centers would attract production operations of a weight losing commodity. In both cases, the availability of low cost nuclear power (or heat) over wide geographic areas must be combined with sufficiently important potential advantages of market, raw materials or other influence to change the balance away from a location that is now strongly affected by low cost power from hydroelectric sites or perhaps from natural gas. Where a process shift is involved, the logic of the situation suggests that bulk energy consumption is entering production processes for the first time and the location of the site of production is reoptimized anew taking account of energy costs in greater measure than before.

The aggregative effects of reduced energy costs on the national economy will be quite small as compared with the total of all other economic activities. AEC estimated in its 1962 "Report to the President" that by the end of the twentieth century, projected uses of nuclear power would result in cumulated savings in generation costs of about $30 billion, the discounted present value of which would be $10 billion at 5 per cent interest.[31] The estimate was based on a simple subtraction of expected nuclear power costs from expected conventional power costs using AEC's projected schedule of nuclear power additions. In comparison with an annual rate of Gross National Product close to $625 billion in 1965 and a projected GNP of $2007 billion in year 2000,[32] the cumulative total in savings do not appear large. But other aggregative effects must be considered.

With a reduction in the price of energy, consumers gain purchasing power, some of which will normally be used for the purchase of additional energy and the rest of which will be used for other purposes. Over a long enough period of time, increases in real income can result in more leisure. All increases in consumption have their secondary and tertiary effects on the suppliers of the goods that are being brought into service, with the result that the effects are perpetuated in infinite regression. It is the total cumulation of all secondary and higher order effects with the initial cost savings that produces a more comprehensive measure of a given real cost reduction. In any particular case, the total effect of the infinite series of derived effects will be to increase the initial benefit (as, e.g., estimated by AEC) several fold, probably by a factor greater than 1.5 and less than 6.0.[33] It is still clear that the aggregative effects of the cost savings will be small as compared with the cumulated Gross National Product for the same years.

Other Uses of Nuclear Power

One possible use of heat from nuclear reactors is for central district urban space heating. This application is similar to the generation of electric power except that steam heat is distributed directly to the consumer location. Space heating consumes 20 per cent of the total energy in the United States today,[34] but at the present time the heat losses from steam distributed by central district plants, combined with the required economies of scale for nuclear power plants, limit prospective applications to densely populated areas where cold winters are experienced. Schurr and Marschak in their exploratory study found that the combination of conditions that might make central district space heating economically attractive are most likely to be found in New York, Boston, Buffalo, Chicago, Milwaukee and Newark, Patterson and Jersey City.[35] The principal difficulty is in the siting requirements. To make such applications economically viable, the nuclear reactor must be located in the middle of a densely populated area. We are not yet ready to approve such location from the standpoint of public safety.

Another closely related application is the generation of nuclear power for the propulsion of ocean vessels. The nuclear ship Savannah immediately comes to mind, but the author is informed that costs on this vessel are unrepresentative of current nuclear propulsion technologies. An approach to the question of costs can be made, however, by noting that the U. S. Navy uses a factor of 1.5 as a rule of thumb in relating nuclear power plant construction costs to those of conventional power plants of the same size for surface vessels.[36] Operating costs are higher, but the extent is not clear from information available.[37] For smaller power plants, such as used in aircraft, locomotives and automobiles, nuclear propulsion seems out of the question for the indefinite future (unless for military purposes, where cost is not a deterrent). If nuclear power is used in the private sector, it will probably be in the form of electrical energy supplied from a central power station.

A step further removed is the direct use of nuclear heat for industrial processes. This topic was the subject of extensive investigation by AEC in the late 1950's. Two difficulties were encountered. First, reactor technologies that are low cost today produce heat at relatively low temperatures as compared with the needs in many industrial processes. Second, before low cost energy can be obtained from a nuclear reactor, it must be of enormous size. As a result of these limitations in combination, "no potentially economic process heat application was found."[38]

A new energy consumer, as yet unimportant in the national (or world) energy economy, is desalinization of water. As population grows and (in the United States, at least) water consumption per capita increases, it is prudent to look ahead to increased needs for fresh water for all purposes. Nuclear power offers some promise as an energy source for distillation. Conventional energy plants in the United States have been built in the range of a million gallons per day to produce water at a cost of about $1.00 per thousand gallons.[39] This is about twice the acceptable cost of municipal water in many parts of the United States, about four times the cost of industrial water and seven or eight times that which is acceptable for most agricultural uses.[40] If plant output is increased approximately a thousand fold to a billion gallons per day, numerous nuclear plant designs suggest that fresh water can be produced from nuclear reactors at costs well within the range of municipal and commercial prices today.[41] With combined fresh water and nuclear electric power production (electric power in the range of 600 to 1200 MW), some of the costs could be borne by electric power sales (assuming large power markets could be reached) and distilled water might be sold at a price low enough to reach the upper range of prices now acceptable for irrigation.[42] The prospect would seem to be of even greater significance to those interested in water rather than energy resources, but the fact that it is based on design, not experience, must be kept in mind.

Solar Energy

The attraction of solar energy is in its abundance and, from our standpoint, unlimited availability over time. Solar energy reaching Continental United States annually is about $14,700 \times 10^{12}$ kwhr; that reaching the land areas of the world, $246,000 \times 10^{12}$ kwhr.[43] Compare projected energy needs by Schurr et. al. for the United States in 1975 at 21.8×10^{12} kwhr.[44] This figure corresponds to the upper limit of a range of energy consumption estimates for the same year made by the present author and extended to an energy consumption upper limit of 52.1×10^{12} kwhr in year 2000.[45] If only a fraction of one per cent of the solar energy reaching Continental United States could be usefully employed, it would satisfy all of our energy needs as far in the future as we can predict them.

Solar energy is like nuclear energy in that fuel transportation costs are of no significance. The solar climate varies with the latitude and season of the year but is adequate for many applications over large areas of the world between the forty-fifth parallels north and south. Solar equipment is also like nuclear equipment in that it is capital intensive. The initial investment constitutes a large fraction of total lifetime expense for solar devices. In several other respects, solar energy has economic characteristics opposite those of nuclear power.

Differences in quality are readily apparent. For nuclear power, Roddis cites evidence of load following characteristics and reliability that surpasses even those of the best fossil-fueled plants.[46] Solar energy, on the other hand, is of very low quality due to its low intensity and interruptibility. Low intensity limits the temperatures at which solar energy can be used except where optical focussing systems are employed. For a sufficient expenditure on a solar focussing collector, almost any temperature attainable on earth can be achieved. Interruptibility likewise has its costs, depending on the use envisaged. Energy storage can bridge the nocturnal disappearance of the energy source or can extend collected energy availability over longer periods of time. Energy storage has its costs, but is not always necessary. Low quality interruptible energy might be quite satisfactory in some uses, depending on the design of the prime mover. The interruptibility of solar energy does not prevent its use in certain applications such as water pumping for irrigation. Indeed, there is a rough correlation between the availability of solar energy and the need for irrigation water. The correlation is better for space cooling but tends to be roughly inverse for space heating. Practically continuous energy must be available for still other uses such as food refrigeration and manufacturing. Energy storage costs assume different importance for different applications and will, of course, vary with the solar climate.

Solar energy is also opposite of nuclear power in its scale (or size) economies. Nuclear power tends to find its comparative advantage in mammoth applications, as we have noted. Solar devices are comparatively better in midget applications. Typical of the latter are roof hot water heaters, small scale distillation and, in recent years, midget power units for earth satellites. Solar space heating remains largely in the technological future, but when it comes, it will be best suited for isolated locations where conventional fuels are expensive. In contrast, we have noted that nuclear energy might be used for central district space heat, but only in exceedingly dense population centers. Other examples will become apparent in the course of succeeding analysis.

The solar equipment discussed herein will be for power (terrestial applications), space heat, and water distillation. There are, of course, other applications of solar energy: for cooking, for agricultural drying, for high temperature production in a solar furnace, to name a few. Solar power is potentially important in economic development. Solar space heat offers promise of some day carrying a significant fraction of the space heat load. Solar distillation is important from a long-term water resource standpoint. But all are presently limited by cost considerations. The prospects are sufficiently encouraging, however, to justify an analysis of solar energy's current status.

The solar energy systems will be evaluated using a fixed radiation intensity of 180 Kcal/cm.^{2},yr. This is a high level of radiation, found in Southwestern United States, North Africa, the Near East, Central India and other locations favorably situated for solar energy.[47] Solar radiation is not the only climatological variable that affects the performance of solar equipment. Two others important in determining heat losses are ambient temperature and wind speed. A comprehensive analysis would take account of the last two, but the results would be oriented more specifically to a fixed location.[48] For present purposes, it will be sufficient to use fixed overall energy conversion efficiency factors. The use of such factors relies on a mean representative effect of other climatological variables, as noted above, and also constitutes an oversimplification in the sense that conversion is typically a nonlinear function of energy intensity. The fixed overall energy intensity being used is, in truth, the average of a yearly pattern that shows considerable variation on a daily and on an hourly basis.

A second difficulty with the use of a single yearly average radiation is that energy storage needs depend on the frequency distribution of radiation intensity. The duration of cloudy weather on any one day must be considered as part of a pattern in which preceding cloudy or sunny days have predetermined the energy that will be in storage at the beginning of that day. Thus, it is necessary to consider patterns of radiation described in a complicated statistical manner or to evaluate equipment performance for a specific identified period (e.g., a year) of weather observations. For the latter purpose, a recursive system such as shown in Figure 1 is required. This system is being used by the author for computer evaluation of solar equipment.

The use function of output energy is equally important. A use function that requires energy during daylight hours only will need less storage than one intended to supply electricity for night lighting. For the sake of equipment evaluation herein, the problems created by the frequency distribution of sunlight and by the use function will not be explicitly resolved. Instead, equipment will be evaluated with different assumed requirements for storage expressed as number of days capacity at the assumed solar radiation intensity level of 140 Kcal/cm.^{2}, yr. In practical applications of solar power units, cases will undoubtedly be encountered in which it is not desirable to attempt to provide sufficient storage, whatever the use function. Such a case is found where the yearly weather pattern regularly brings extended cloudy periods, as in the monsoon climates. In such instances, standby conventional equipment will have to be provided if a solar energy source is to be used at all, or, it might be necessary to employ an alternative use function, depending on the value of energy input for the case at hand. A third possibility is to integrate a wind power system in parallel with a solar power system. In many cases, this approach offers some promise of reducing storage needs. The exact advantages, if any, depend on a comparison of costs of wind power and storage for a given output.[49]

The two principal components of most solar devices are the collector and the storage unit. Where a high temperature heat source is required, as in most power systems, a focussing collector is used. This in turn requires that direct sunlight (direct radiation) be available. Other collectors, such as used for space heating, are nonfocussing and can collect energy in the form of diffuse radiation on cloudy days. Diffuse radiation accounts for about 15 per cent of the radiant energy on clear days. On cloudy days, diffuse radiation may actually increase in absolute value if sky cover is thin or may decrease (in absolute value) if sky cover is heavy.[50]

Economic optimization of equipment design is achieved in any given climate by balancing the cost of collector against the cost of storage for a given energy output with a given level of reliability. Refer to Figure 1. Thus, a given level of ϕ, say 99 per cent, can be achieved either by increasing the size of the collector or by increasing the capacity of storage. When the size of collector is increased, more energy is collected during sunny days and storage is kept to a level close to its capacity. At the same time, more energy is lost through storage overflow, γ_m. When the capacity of storage is increased for the same collector size, more is stored, less is collected and less is lost through storage overflow.

In existing equipment, collector expense is typically higher than storage expense. This means that optimization usually requires an expansion of expenditure on storage. The optimum is achieved when the marginal expenditure on collector and the marginal expenditure on storage both yield the same incremental gain in output at the given ϕ level. Needless to say, it will not be possible to carry out such optimization with the simplified approach used herein. The ϕ reliability of equipment cannot be specified at the present time (or in absence of a more specific climate description and use function) and hence we can hope only to cover the probable range of costs. One might think of increased system costs for the same average output as expenditures for the sake of higher quality energy.

Solar Power Systems

Three types of solar power systems will be considered: (1) thermoelectric; (2) thermodynamic (Tabor); and (3) solar pond. Cost estimates for the three are shown in Table 5. The technologies are in various states of development and cost estimates are by no means as firm as they were for nuclear electric power. Annual equivalent capital costs are calculated at 6 per cent interest with sinking fund depreciation. No tax burden is imputed to the solar equipment in recognition of differences in tax structures throughout the world. It will be noted that fixed kilowatt capacity is rated at an energy intensity considerably above the yearly average, though, of course, the kilowatt-hour output is based on the yearly average.

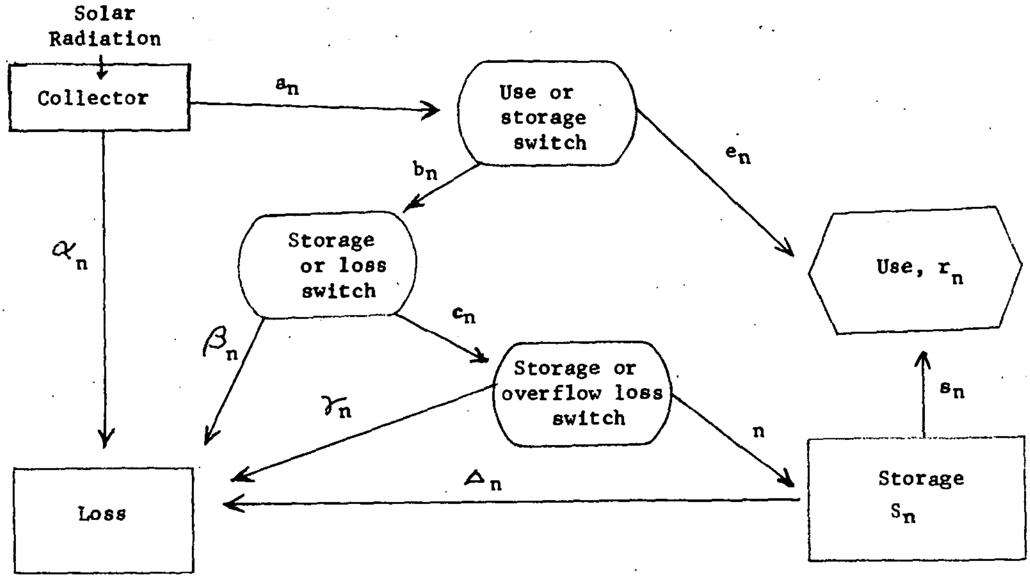
The thermoelectric and thermodynamic systems are focussing systems and hence use only direct normal radiation. The thermoelectric system uses a paraboloid reflector which is continuously adjusted so as to remain normal to the solar beam at all times. The Tabor unit achieves energy concentration by focussing direct radiation in long cylindrical reflectors that are adjusted on an east-west axis in such a way as to set the aperture of the cylindrical reflectors approximately normal to the sun's rays at solar noon. The solar pond is a nonfocussing device that uses all radiation (direct plus diffuse) on a horizontal surface. In making the calculations for Table 5, direct radiation was separated from diffuse radiation using methods described in the reference cited by footnote 50, above.

The thermoelectric system consists of an 8-foot diameter paraboloid collector focussed on a thermocouple cluster. The load and a lead-acid storage battery are connected in such a way as to achieve maximum electric power output. An overall energy conversion factor of 4 per cent is used to take account of all energy losses (optical, thermal and electrical). Representative costs are reported, based on a questionnaire survey of manufacturers of thermocouples, adapted from earth satellite power applications. Since the costs are representative, no single physical thermocouple is envisaged. In the questionnaires, respondents were asked to estimate costs on two bases: (1) costs of existing devices, often built for experimental purposes; and (2) costs of similar devices as they might exist with volume production. Costs in the latter category are used for the thermoelectric system.

The Tabor unit focusses energy on tubes in which vapor is heated to drive a highly efficient small turbine designed for the system.[51] Energy is stored by a phase transformation at about 150° C, but other information about storage is not available. A full scale pilot unit of the system has been constructed. The costs have been estimated by Dr. Tabor for production of parts using the technology of the experimental unit.

FIGURE 1

SOLAR ENERGY FLOW DIAGRAM



Notation:

a_n, b_n, c_n, d_n, d_n, s_n	energy flows net of losses in time period n
α_n, β_n, γ_n, Δ_n	energy losses in time period n
r_n	energy needed for use in time period n
S_n	total energy in storage at the end of time period n
K	capacity of storage

Identities:

1. Radiation received in time period n = $a_n + \alpha_n$
2. $a_n = b_n + e_n$
3. $b_n = c_n + \beta_n$
4. $c_n = d_n + \gamma_n$

Functional relationships:

5. $\alpha_n = f_1$ (radiation received in n, other climatological parameters in time period n)
6. $\beta_n = f_2$ (b_n, transfer of energy parameters)
7. $\Delta_n = f_3$ (S_{n-1}, storage parameters)

$$8.\quad e_n = \begin{cases} r_n & \text{if} \quad a_n \geq r_n \\ a_n & \text{if} \quad 0 \leq a_n \leq \quad n \end{cases}$$

$$9.\quad d_n = \begin{cases} c_n & \text{if} \quad K - S_n \geq c_n \\ K - S_n & \text{if} \quad K - S_n \leq c_n \end{cases}$$

$$10.\quad s_n = \begin{cases} r_n - e_n & \text{if} \quad S_n \geq r_n - e_n \\ S_n & \text{if} \quad 0 \leq S_n \leq r_n - e_n \end{cases}$$

FIGURE 1 (continued)

Note: 1. All use occurs at the end of a time period
2. Priority of use is e_n, then s_n
3. All energy is put in storage at the end of a time period

Initial conditions:
S_o = amount in storage at time 0
$S = S_o + d_n - \Delta_n - s_n$

Performance measurement:

Let $\phi_n = \begin{cases} 1 & \text{if } e_n + s_n = r_n \\ 0 & \text{if } e_n + s_n < r_n \end{cases}$

Then $\phi = \sum_n \phi_n$ is the number of time periods sufficient energy was available

Source: The author is indebted to Professor Jesse Shapiro for this conceptualization.

TABLE 5

ESTIMATED SOLAR POWER COSTS

(180 Kcal/cm^2,yr. global radiation on a horizontal surface = 194.5 kwhr/ft^2,yr. global radiation on a horizontal surface)

	Thermoelectric unit	Thermodynamic (Tabor) unit	Solar Pond (based on design only)
Available radiation, kwhr/ft^2,yr.	238 direct normal	185 direct, with adjustment around east-west axis	194.5 global on horizontal surface
Size, KW[a]	0.175[d]	4.64	14,000/km^2 [g]
Output, kwhr/yr.	481.[d]	10,070.[e]	31.5 X 10^6/km^2 [g]
Capital cost[b]			
$	295.	3100.	roughly 3.0 X 10^6 [h]
$/KW	1690.	668.	214
Annual equiv. capital cost, mills/kwhr.[c]			8.22[i]
no storage	83.3	51.6	
1 day storage	103.0	56.6[f]	
2 day storage	121.8		
3 day storage	141.0		
5 day storage	179.6		
Operation and Maintenance	?	?	about 4.0

[a] Installed capacities are rated at the high energy intensity level of 80 cal/cm^2,hr. (= 757 kwhr/ft^2,yr.)

[b] Capital cost is exclusive of storage for the thermoelectric and thermodynamic systems, but not for the solar pond.

[c] Annual equivalent capital cost is calculated using 6 percent interest with sinking fund depreciation. Different components of each system are evaluated using different expected useful lives. The term "1 day storage" means 24 hours of storage.

[d] Assuming 4 percent energy conversion efficiency.

[e] Computed by linear extropolation from the 10,000 kwhr output reported by Tabor with an available insulation of 185.0 kwhr/ft^2,yr.

[f] The Tabor thermodynamic unit includes only 16 kwhr of storage, which at the assumed rates of production will last 18 hours. A standby boiler and controls are included in the capital cost list above. The standby equipment can be obtained to burn any suitable fuel such as kerosene, gas, fuel oil, wood or agricultural wastes. Beyond the 16 kwhr of storage, the designers recommend use of the standby.

[g] Assuming 1½ percent energy conversion efficiency.

TABLE 5 (continued)

[h] Calculated by using Tabor's figure of $250,000. for the bare pond with free brine available, plus $200/KW for power generating equipment of the type required as in R. L. Hummel, "Power as a By-Product of Competitive Solar Distillation", United Nations, E/Conf. 35/S/15 (Rome, 1961). A twenty year life of these components was assumed.

[i] Storage and collector are combined in the solar pond. The thermal inertia of the pond is so great that no storage shortage can arise within a time period of weeks or perhaps months after the pond reaches an adequate temperature for operation.

Source: Thermoelectric System: Representative figures from questionnaire survey conducted by Richard A. Tybout and George O. G. Löf, Winter 1961-62.
Thermodynamic System: H. Tabor and L. Bronicki, "Small Turbine for Solar Energy Power Package", United Nations E/Conf. 35/S/54 (Rome, 1961), supplemented by personal correspondence.
Solar Pond: H. Tabor, "Large Area Solar Collectors (Solar Ponds) for Power Production" United Nations E/Conf. 35/S/47 (Rome, 1961), except as noted in footnote h.

The solar pond is not yet a technologically proven device. Also conceived by Dr. Tabor, the object is to suppress convection in a stationary pond of water and hence to use the water as an insulator over an artifical black bottom about 1-2 meters deep. To prevent heat transfer by convection, Dr. Tabor and his associates at the National Physical Laboratory of Israel have attempted to stabilize a density gradient of magnesium chloride or other suitable salt to have a high concentration (and high density) at the bottom tapering off to negligible concentration at the top. Numerous technological problems have been encountered,[52] among them the problem of extracting heat from the bottom while maintaining a tolerable temperature gradient. Prospective costs (contingent on technological success) are worth noting. The data are given in square kilometers of surface, indicating something of the size of an operating pond envisaged by its designers. If fresh water is at a premium, it would be possible (other problems solved) to combine distilled water production with electric power production to the economic advantage of both.

All of the solar power systems shown in Table 5 have costs at least one order of magnitude above those of nuclear power and even so are straining at the edge of the technically feasible. Strictly speaking, however, solar and nuclear power are not comparable because of differences in size. Also relevant is the fact that the technical manpower devoted to solar energy has been infinitesimal compared with that which has been devoted to nuclear power.

The small size of the solar power units places them in competition with diesel electric power. The cost of the latter in overseas installations is often relatively high. For example, as part of current efforts for the development of the Brazilian Northeast, a large number of diesel plants are being installed, ranging in size from 28 KW to 250 KW capacity.[53] The plan is to establish the same rates for electric power throughout the area regardless of the location of the diesel units. In point of fact, there is a fifty per cent variation in cost of diesel fuel among places to be served. The rate to be established is 46.3 mills/kwhr in the early years of the project, ultimately to be reduced to 36.9 mills/kwhr as higher use factors are obtained. With regional variations in diesel fuel costs, there are localities where the true costs are of the same order of magnitude as the Tabor unit, though a number of difficulties remain in making the comparison. For example, the dieselization program requires the training of large numbers of service mechanics. What would be the requirements with solar power? Anticipated daily use patterns do include night lighting in Northeast Brazil, but also important daytime loads. Similar findings apply to high diesel fuel areas of rural India. A full analysis of the comparison between diesel and solar power cannot be made here, but it is clear that solar power costs are of the right order of magnitude for certain applications in the small power field. If, as a nation, we are interested in the energy resource problems of less developed areas, it appears that solar power warrants increased attention. Enough has been said to show that its applications will be complementary with nuclear power from an economic development standpoint.

Solar Space Heat

The greatest potential bulk market that appears within reach of solar technologies is in space heating. As previously noted, approximately 20 per cent of all energy consumed in the United States is for space heat.[54] Putnam estimates that by year 2000, solar space heat will carry one-fifth the total comfort heating load.[55] One might infer that the prospects are at least as attractive at the same latitudes (north and south) throughout the world.

Solar space heat can be made available in greater or smaller degree by the architecture of a building without any special solar energy equipment. All buildings with south-facing windows (north-facing in the southern hemisphere) derive considerable direct heat from the sun. Design for capture of this portion of the total solar energy and design for other purposes are inextricably related. The same can be said of thermal insulation, of the heat absorbing qualities of interior furnishings and other attributes of any given structure. Overall optimization of architectural and solar heating design is required for each separate location, though for purposes of the broad general comparisons to be made herein, it is sufficient to consider a single standard dwelling in all locations.

A related complication is found in multiple outputs of the collector system. A solar hot water heating component is generally added to the space heater. Space cooling arrangements and facilities can be included. The result is to produce several outputs all of which use some parts of the solar equipment in common and all of which have their own incremental costs. Cost finding in such cases becomes complicated and some semi-arbitrary cost allocations cannot be avoided.

An entirely different kind of output that can be furnished by solar collectors is shelter. Solar collectors may constitute the roof and/or south wall of a building. In such cases, they furnish a shelter service that would otherwise require the construction of a conventional roof and/or wall. The shelter and energy outputs of the collector are different products with a common cost. It is appropriate to recognize this in calculating the cost of solar space heat.

The solar energy system to be analyzed in the present comparison avoids the problem of allocating costs among space heating, space coding and shelter by the simple expedient of including only a single output, heat, which is used for two purposes, space heating and hot water heating. The total useful heat for both purposes lumped together is evaluated at the cost of the solar energy system <u>less</u> the capital cost of a conventional furnace avoided. The solar energy "costs" so obtained are then compared directly with conventional fuel costs, for once correction has been made for the conventional furnace, the only other costs avoided by having solar heating is the fuel cost. Since solar heating requires a large capital investment and very low operation and maintenance expenses, this means that the annual fixed charge on capital again assumes crucial importance. The comparisons will be made using a 6 per cent imputed interest with sinking fund depreciation. No tax burden is assigned since solar heating is best for private residences, not for commercial buildings unless small (1 or 2 story) buildings are considered. Capital used for business purposes would have to be evaluated with due recognition of an additional tax responsibility.

Operation and maintenance on a solar energy system consist of electricity consumed, annual cleaning of the collector cover and whatever repairs are necessary. The system can be designed in such a way as to require very little maintenance and have a long life (25 years). Such a system is considered herein. Alternatively, a cheaper structure can be used, especially for the collector, at the expense of higher maintenance and shorter life. Then, the system is less capital intensive and more labor intensive. The higher the cost of capital relative to labor (one's own labor, if appropriate), the more economically efficient it is to use a cheaper, less durable collector.

Table 6 gives estimates of solar heat costs for hot water plus space heat in a standard (representative solar heated) house located in different parts of the United States. Costs shown in Part A are for a solar heating system in current use for heating a residence near Denver. The collector is mounted separately at a southernly tilt on a flat roof. The collector area is relatively small compared with house heating needs and, in fact, supplies only about one quarter of the heat required over the course of a year. A conventional auxiliary furnace supplies the remainder. Costs in Part A are given under two headings, "experimental" and "commercial." The experimental unit is the one actually in operation, except as noted in footnote f of the table. The commercial unit is of the same design as the experimental unit but with costs estimated for mass production of the parts and corresponding improvement in techniques of assembly and installation. The estimates have been carefully compiled but in their nature are subject to normal estimating errors.

TABLE 6

SOLAR HEAT COSTS

Part A
Colorado House Solar Heat Costs, dollars
(Collector Area = 530 square feet)

Hot Water Components	Present Unit (Experimental)		Prospective Unit (Commercial)	
Capital				
Solar equipment	250		50	
Assembly and installation	150		50	
Standard gas heater	230		230	
Total	630		330	
Space Heat and All Other Components				
Capital				
Collector	3200		1200	
Storage	350[f]		350[f]	
Special controls and equipment	1230		200	
Standard equipment	730		700	
Assembly and installation	3840		800	
Total	9350		3250	
Saving on conventional furnace	-800	-600	-800	-600
Net capital cost	8550	8750	2450	2650
All Capital Costs	9180	9380	2780	2980
Annual equivalent capital costs[a]	704.	735.	218.	235.
Annual operating and maintenance	20.	20.	20.	20.
Annual Total	724.	755.	238.	255.

Part B
Performance of Standard House with Long Term Average Insolation

	Blue Hill Mass.	Medford Ore.	Columbia Mo.	Atlanta Ga.	Albuquerque N.M.
Degree days/yr.[b]	6,392	4,547	5,113	2,826	4,389
Conventional furnace saving, $	800	600	800	600	800
Collector Area, ft^2	1,410	1,970	1,280	640	710
Capital costs, $[c]	5,780	8,090	5,280	3,070	3,130
Annual costs, $					
Equivalent annual capital costs[a]	452	634	414	241	245
Operation and maintenance[d]	53	74	48	24	27
Total	505	708	462	265	272
Insolation (tilted at latitude plus 15^o)	695	1,172	744	391	558
Solar house heat supplied, 10^6 BTU/yr.	169.4	159.1	119.4	98.9	123.9
Solar water heat supplied, 10^6 BTU/yr.	24.5	24.4	24.0	23.0	23.5
Total solar heat supplied, 10^6 BTU/yr.	193.9	183.5	143.4	121.9	147.4
Solar energy cost, $/10^6$ BTU	2.60	3.86	3.22	2.08	1.85

TABLE 6 (continued)

Part C
Conventional Fuel Costs, $\$/10^6$ BTU[e]

	Boston Mass.	Portland Ore.	St. Louis Mo.	Atlanta Ga.	Albuquerque N.M.
Anthracite	1.86				not
Bituminous coal		2.22	1.33	1.53	available
Fuel oil	2.04	1.88	2.13		
Gas	1.62	1.62	1.06	1.06	

[a] Calculated using 25 year expected life with sinking fund depreciation and 6 percent interest rate. Implicitly the same treatment is being given to capital saved on conventional furnace as to solar equipment capital.

[b] The number of degree days is computed by adding the differences between the average daily temperatures (in^{o}F) and 65^{o} F for all lower atmospheric temperatures.

[c] Capital costs are based on prospective commercial unit adjusted as follows: (1) collector plus assembly costs are assumed the same per square foot of collector area in all locations as in the Colorado house prospective commercial unit; (2) all other solar heating system costs (including both space and hot water heating) are assumed identical in all other locations as in the Colorado house prospective commercial unit; and (3) conventional furnace costs saved are subtracted in the indicated amounts from the total found in steps (1) and (2).

[d] Operation and maintenance costs based on Colorado house prospective commercial unit prorated by area of collector for each location.

[e] The following national average heat efficiencies were used: gas, 80 percent; anthracite, 62 percent; bituminous coal (stoker), 59 percent; oil, 57 percent; and bituminous coal (hand fired), 48 percent.

[f] 3,000 gal. water tank substituted for rock bed in actual use at Colorado house. Cost of tank provided by E. Speyer. See Source for Part B.

Source: Part A. Costs reported on experimental unit by owner of Colorado house, G. O. F. Löf, except as indicated by footnote f. Cost estimated for commercial production of same solar heating system by G. O. G. Löf.

Part B. Fundamental data on performance are from E. Speyer, "Optimum Storage of Heat with a Solar House", Solar Energy, Vol. III (December, 1959), pp. 34-40. Costs are from Part A, as explained in footnotes.

Part C. American Gas Association, Gas Facts 1961-62, p. 238.

It will be noted that a standard gas heater is included with the solar hot water costs. This is an oversized heater that will serve the function of furnishing auxiliary heat in the fictitious house used as a standard (not in the actual Colorado house). Since our standard house has water storage of solar heat, the oversized hot water heater is connected in such a way as to deliver additional heat to the water in storage when, as and if needed.[56]

Part B is based on calculations made by Speyer for the standard house in different locations.[57] Speyer's calculations were based on average weather conditions month-by-month and took account of patterns of weather in sequence, insofar as such patterns are represented in averages.[58] Needless to say, different results would have been obtained if nonaveraged data had been used on an hour-to-hour or day-to-day basis. The object of design was to satisfy average weather requirements on the assumption that gas heat would be used for hot water during the months of December, January and half of February. The optimum storage capacity was found to be 3000 gallons of water in all locations shown, but collector area varied widely. The solar heating system used by Speyer was not completely described in his study, but was clearly representative of technologies in existence today.[59] It is used here to describe the performance of the solar heating system costed for the Colorado house in Part A.

The effect of different weather conditions on output are illustrated in Part B. Thus, the collector area required in Medford, Oregon is considerably greater than that in Blue Hill or Columbia despite the fact that Medford has a lower average number of degree days. This results from the high frequency of overcast winter skies in Medford. The more southern locations in the United States can achieve relatively greater advantage from solar heat, as exemplified by Atlanta, but the greatest advantage is in locations such as Albuquerque where a high heat demand, due to altitude above sea level in this case, is combined with a relatively low latitude and clear skies.

Part C in Table 6 gives the basis for an approximate cost comparison. Since capital investment in conventional furnace facilities has been subtracted from the capital costs of the solar heating systems, the remaining costs of solar heating capital are comparable to the fuel costs from conventional energy sources. The latter are shown in Part C of Table 6 for locations in the same climate areas used by Speyer (except for Albuquerque, for which fuel cost data were unavailable). The approximate nature of the comparison should be emphasized. The demands on the solar heating systems in different locations were a function of Speyer's standard house design. Architectural improvements would reduce the requirements of solar energy, but also the requirements for conventional heat. Differential effects of architectural changes could not be investigated in the present comparison.

The cost comparisons in Table 6 show that present technologies, even with the advantage of commercial production, do not offer as low a cost of heat as that afforded by commercial fuels in the special context of the comparison. Nevertheless, solar heat costs appear sufficiently close to conventional heat costs that any one of a number of circumstances could make solar heating economically attractive. A technological break-through in collector design would have the greatest effect. Short of this, the design of multiple purpose units that serve a shelter purpose and a space cooling purpose (where this last output has sufficient value to cover its own special equipment costs) would reduce space heating costs. Several such designs are in use in various experimental buildings, but they have not benefitted from the commercial scale of production assumed for the unit in Table 6.

The requirement of electrical energy to drive pumps and blowers reduces the prospects for use of solar space heat in less developed countries. Technologies combining solar power and solar space heat can, of course, be designed for use where electricity is not available, but with the disadvantageous position of solar power today, these would be of still higher cost. Fortunately, space heating demands are not as urgent as other kinds of energy demands in most underdeveloped areas.

Solar hot water heating, on the other hand, is already widely practiced. About 350,000 units were in use in Japan in 1961 and about 10,000 in Israel.[59] A large number of solar hot water heaters are found in North Africa and until gas became cheap in Florida, they were in frequent use there. Many are of the simple box type, quite inexpensive and, of course, subject to vicissitudes in the arrival of solar energy. The energy load carried by solar hot water heaters is small, but not to be ignored. Speyer assumed a hot water demand of 120 gallons per day heated to 140° F. Compare in Table 6 the relative heat needed to satisfy this demand with that required for space heating in the different locations, remembering that in Speyer's calculations the hot water load is satisfied by conventional fuel for $2\frac{1}{2}$ of the twelve months.

Solar Distillation

Several hundred small home solar distillers and quite a few of larger size are in operation in the arid regions of Mediterranean North Africa and the Near East. Others can be found, often on an experimental basis, elsewhere in the world. Representative costs have been estimated for three kinds of distillation technologies in Table 7. The small roof distiller is made of blackened asbestos cement with a glass cover. The tilted wick (Telkes) unit evaporates water from a replaceable terry cloth surface over which brine descends. The deep basin design evaporates by batch or continuous process from ponds filled to a depth of about 1 foot.[60] A number of other technologies are now under investigation, including forced convection systems, multiple effect evaporation and the use of inflatable plastic covers of various designs.

The data shown in Table 7 bring out once again the emphasis of solar technologies on small scale applications. Even at the relatively larger output of 100,000 gallons per day, solar distillation in the United States is more expensive than conventional fuel distillation. The costs of the latter have been estimated at an attainable level of $1.50 per thousand gallons at the 100,000 gallon per day output.[61] The costs of solar distillation are close enough, however, that communities in the Mediterranean area find it economically advantageous to install solar distillation facilities. Their calculations on this point are sometimes influenced by local unemployment (which can be used for solar plant construction) and the coincident problem of acquiring foreign exchange to finance fuel imports. The comparative advantage of solar energy in this case is analogous to that potentially existent for solar power applications.

Future Applications

There is ample prospect that nuclear power will be more widely used in the United States, hopefully with due recognition of its social costs as well as its economic benefits. It is also quite conceivable that solar energy will assume some of the space heating load in the American economy before the end of the twentieth century, but this depends on further technological progress.

In overseas areas, the significance of unconventional resources is comparatively greater. Conventional energy resources in this country show no signs of exhaustion in the foreseeable future or of experiencing important real cost increases before the end of the present century.[62] The same cannot be said of several other world regions.

Western Europe, the world's historic coal exporting region, is now a net importer of all fuels.[63] High density markets and high energy costs have given impetus to substantial programs for installation of nuclear power, in Britain and on the continent. The same logic applies to Japan.

Even more difficult is the energy resource position in which most of the less developed nations find themselves. The most serious energy resource problems are in prospect before the end of the twentieth century for the Latin American countries as a whole, for Asia except the Soviet Union and mainland China, and for Africa.[64] If the low income nations in these regions are to achieve the standards of living they

TABLE 7

ESTIMATED SOLAR DISTILLATION COSTS

(180 Kcal/cm^2, yr. global radiation on a horizontal surface = 194.5 kwhr/ft^2, yr. global radiation on a horizontal surface)

	Roof Evaporator[a]	Tilted Wick Still[b]	Deep Basin Still[c]
Available radiation, kwhr/ft^2,yr.	194.5 global, on horizontal surface	226 global, on tilted surface[e]	194.5 global, on horizontal surface
Size, ft^2 surface	12.4	25	1.1 X 10^6
Output, average annual, gal/day	1.435	4.21	100,000
Capital cost, $	61.5	38.0	1.12 X 10^6
Expected life, years	20	5-10	50
Annual equivalent capital cost, $/1000[d] gal.	10.27	5.88 - 3.36	1.95
Operation and maintenance, $/1000 gal.	4.00	1.63	0.263
Total cost, $/1000 gal.	14.27	7.51 - 4.99	2.21

[a] Representative costs based on hundreds of units already in use in Mediterranean North Africa.

[b] Costs of experimental units, 20 or 30 of which have been constructed. Costs could be expected to decline somewhat with volume production.

[c] Costs estimated by scale-up of 300 gallon per day experimental unit, taking advantage of minor technological improvements.

[d] Annual equivalent capital costs calculated using sinking fund depreciation with 6 percent interest.

[e] Tilted at fixed angle so that plane of surface is normal to solar beam at the equinoxes.

Source: Estimates were all derived from questionnaires circulated by Richard A. Tybout and George O. G. Löf in Winter, 1961-62.

so strongly desire, they will have to rely in part on fuel imports and/or expand their use of unconventional energy resources. Indeed, if they are to attain even moderate rates of per capita income growth, they must face the same choice.

Unfortunately, both atomic and solar energy involve capital intensive technologies. The scarcity of capital in less developed countries is well known. This fact works in favor of conventional fuel applications which, as we have noted throughout, are less capital intensive. Working in the counter direction, of course, is the expense of conventional fuel transportation, often over tedious overland ways. Where fuel imports are concerned, there is the additional disadvantage of foreign exchange problems. The value of foreign exchange is typically greater to a less developed country than is its domestic currency. Moreover, the ratio of the value of domestic currency to foreign exchange tends to be lower the lower the per capita gross national product of the country.[65] Not only does this fact work against conventional fuels, but it can work against nuclear power, most of the expenses of which require the use of foreign exchange.[66] A large part of the expense for solar equipment, on the other hand, can be met by domestic manufacture in less developed countries.

Additional insights can be obtained by considering the kinds of markets nuclear power and solar energy can serve. The high quality of nuclear electric power has been noted. It can be useful for the high density markets of new industrial centers and large urban areas. With some improvements in cost, solar energy can help the low density areas where cottage industry, village refrigeration, water pumping and like applications are the needs of the hour. The two unconventional energy resources are complementary insofar as their uses in less developed areas can be foreseen today.

Footnotes

1. J. R. Elizondo, "Prospection of Geothermal Fields and Investigations Necessary to Evaluate their Capacity," United Nations E/Conf. 35/GR/3(G), (Rome, 1961), p. 74.

2. P. C. Putnam, Energy in the Future (New York, 1953), p. 191.

3. R. A. Tybout, Atomic Power and Energy Resource Planning, Monograph 94, Ohio State University Bureau of Business Research (1958), pp. 21-22.

4. Jersey Central Power and Light Company, Report on Economic Analysis for Oyster Creek Nuclear Electric Generating Station (February 17, 1964).

5. U. S. Atomic Energy Commission, Civilian Nuclear Power, Appendices to a Report to the President - 1962 (Washington, 1962), p. 58, Table 4.

6. "Cooperative Power Reactor Demonstration Program, 1963," Hearings before the Subcommittee on Legislation of the Joint Committee on Atomic Energy, 88th Congress, 1st Session (July 9, August 7 and October 15, 1963), Exhibit A, Tables I and II, pp. 23-25.

7. See, for example, costs in the Cooperative Reactor Demonstration Program, "AEC Authorizing Legislation, Fiscal Year 1965," Hearings before the Joint Committee on Atomic Energy, 88th Congress, 2nd Session (February and March, 1964), Appendix 1.

8. For a discussion of social costs in the earlier nuclear power plants, see R. A. Tybout, "Atomic Power and the Public Interest," Land Economics, Vol. 34 (November, 1958), pp. 281-289.

9. General Public Utility power system, composed of financially integrated operating utilities.

10. The significance of "annual equivalent" capital costs is explained in the context of other methods of time discounting in R. A. Tybout, "Economic Criteria for Evaluating Power Technologies in Less Developed Countries," U. S. Papers Prepared for United Nations Conference on the Application of Science and Technology for the Benefit of Less Developed Areas, Vol. 1 (Washington, 1963), pp. 177-201.

11. See especially Philip Sporn, "A Post-Oyster Creek Evaluation of the Current Status of Nuclear Electric Generation," in Joint Committee on Atomic Energy, 88th Congress, 2nd Session, Nuclear Power Economics - Analysis and Comments - 1964 (Washington, 1964).

12. Federal Power Commission, Instructions for Estimating Electric Power Costs and Values, (Washington, 1960), p. 24. The FPC figure is made up of the following:

		Percent of Investment
Cost of money		6.75
Depreciation, 6.75% sinking fund		0.77
Interim replacements (straight line)		0.35
Insurance (conventional plant)		0.25
Taxes		
Federal income	3.40*	
Federal miscellaneous	0.10	
State and local	2.35*	
Total taxes		5.85
Total		13.97

*national averages

The above estimates are based on a plant life of 35 years. If reduced to a thirty year life, depreciation would be higher.

13. Op. cit., note 12, supra.

14. G. J. Strathakis, "Nuclear Power Drives Energy Costs Down," Electrical World (October 5, 1964).

15. The Oyster Creek insurance costs are included in operation and maintenance expenses for that plant as shown in Table 1. They are based on the provisions of the Price-Anderson Act.

16. See discussion by G. J. Strathakis, Op. cit., note 14, supra.

17. AEC Release No. E-292 dated August 23, 1962.

18. See "Private Ownership of Special Nuclear Materials," Hearings before the Subcommittee on Legislation of the Joint Committee on Atomic Energy, 88th Congress, 1st Session (July 30, 31 and August 1, 1963) and 88th Congress, 2nd Session (June 9, 10, 11, 15 and 25, 1964).

19. Calculated from Oyster Creek report (Op. cit, note 4, supra), using the 10.39 per cent capital charge there employed.

20. See Commissioner G. F. Tope, "Future Energy Needs and the Role of Nuclear Power," Third International Conference on the Peaceful Uses of Atomic Energy, Geneva, AEC Release dated August 31, 1964, page 4.

21. It is interesting to note that AEC simultaneously charges $43.00 a gram for the same plutonium isotopes in the same form if distributed for non-power uses (research and development or medical therapy). See AEC Release No. F-106, mimeographed, dated May 28, 1963. The inference is that the $10.00 price probably does not represent AEC costs.

22. A full statement of the environmental health problem by AEC follows: "When nuclear activities were small in scale, wastes involving very low specific activities could be discharged to the environment without unduly raising the radiation background level. Freedom to so dispose of them may be increasingly restricted in the future, primarily because of the rapidly increasing amounts and, secondarily, because acceptable environmental limits have been reduced. Hence, it will be necessary for the waste management research and development program to develop, on an expeditious basis, improved and more efficient methods for decontaminating large volumes of low-activity waste and concentrating the radioactive materials removed. In a related sphere, continued support must be given to environmental investigations to: (1) determine the ultimate fate of specific radionuclides in land, in water and in air environments; (2) establish reasonable technical criteria for safe disposal of very low level radioactive effluents into the environment. Such programs are, and must be, pushed with vigor." U. S. Atomic Energy Commission, Civilian Nuclear Power, A Report to the President, 1962 (Washington, 1962), p. 55.

23. Ibid., p. 55.

24. Ibid. Of high level waste disposal, AEC states, "The problem is technically soluble, but costs are not known." p. 55.

25. Op. cit., note 14, supra. The absolute values of his estimates are 4.21 mills/kwhr for a 600 MW plant and 10.37 for a 50 MW plant.

26. Yoram Barzel, "Productivity in the Electric Power Industry, 1929-1955," Review of Economics and Statistics, Vol. 45, (November, 1963), p. 402. This result is based on a cross-section analysis for 1959 of plants that commenced operation in 1953-1955. The sample size range was 28,000 to 1,400,000 kw. In a multiple regression analysis, Barzel reports a coefficient of logarithm of size of 0.109 and a coefficient of logarithm of load factor of 0.373. Both coefficients were highly significant in explaining variations in logarithm of plant productivity.

27. A fuller treatment of this subject will be found in W. Iulo, Electric Utilities - Costs and Performance (Washington State University Press, 1960).

28. Op. cit., note 4, supra, p. 24.

29. Using assumptions somewhat more simplified than those employed here, AEC has forecast a schedule of adoption of nuclear capacity. See Op. cit., note 5, supra, pp. 64-67.

30. S. H. Schurr and J. Marschak, Economic Aspects of Atomic Power (Princeton University Press, 1950).

31. Op. cit., note 5, p. 67. The estimate was reaffirmed by Commissioner Tope in his paper delivered at the Third International Conference on the Peaceful Uses of Atomic Energy in Geneva. See "Future Energy Needs and the Role of Nuclear Power," AEC Release, August 31, 1964.

32. National Planning Association, "Projections to the Years 1976 and 2000: Economic Growth, Population, Labor Force and Leisure, and Transportation," Report to the Outdoor Recreation Resources Review Commission (Washington, 1962), p. 132, Table D-1.

33. For a sample calculation in which derived effects are considered for nuclear power savings, see Schurr and Marschak, Op. cit., note 30, Supra, Ch. 13.

34. S. H. Schurr, B. C. Netschert and associates, Energy in the American Economy 1850-1975 (Johns-Hopkins University Press, 1960), p. 177.

35. Op. cit., note 30, supra, Ch. 12.

36. "A Treatise on Nuclear Propulsion in Surface Ships," prepared for the Chief of Naval Operations and submitted as appendix material in "Nuclear Propulsion for Naval Surface Vessels," Hearings before the Joint Committee on Atomic Energy, 88th Congress, 1st Session (October 30, 31, and November 13, 1963), p. 200.

37. Ibid.

38. Statement by Commissioner James T. Ramey, "Use of Nuclear Power for the Production of Fresh Water from Salt Water," Hearing before the Joint Committee on Atomic Energy, 88th Congress, Second Session (August 18, 1964), p. 3.

39. "Desalination of Water Using Conventional and Nuclear Energy," a report to the International Atomic Energy Agency, Vienna, 1964, included as Appendix A, "Use of Nuclear Power for the Production of Fresh Water from Salt Water," Op. cit., note 38, supra, p. 61.

40. Ibid., pp. 49-50.

41. Ibid., p. 86. With an overall national average consumption of water in the United States of 1700 gallons per day per person for all uses, there are certain seacoast metropolitan areas where the demand would be sufficient to consume the output of a billion gallon per day plant.

42. Idem.

43. P. C. Putnam, Op. cit., note 2, supra, p. 198.

44. S. H. Schurr, B. C. Netschert and associates, Op. cit., note 34, supra, p. 234, Table 64.

45. R. A. Tybout, Op. cit., note 3, supra, Table 1, p. 6.

46. Reported in "Integrating Nuclear Power into National Grids," Nucleonics, Vol. 22 (October, 1964), p. 59.

47. Compare H. E. Landsberg, "Solar Radiation at the Earth's Surface," Solar Energy, Vol. V (July-September, 1961), pp. 95-98.

48. Such an analysis is being conducted by the author using computer simulation and equipment performance characteristics supplied by his collaborator Dr. George O. G. Löf. Five categories of equipment are being evaluated using U. S. Weather Bureau data for eight climates representing all major world climates in the temperate and tropical regions except for "tropical rain forest," for which adequate data are not available.

49. The subject is being investigated by the author, but more meaningful conclusions cannot be drawn at the present time.

50. These relationships, and the problems of determining direct and diffuse radiation intensities from data reported by the U. S. Weather Bureau, will be discussed by the author in a forthcoming paper, "Statistical Separation of Direct and Diffuse Solar Radiation."

51. H. Tabor and L. Bronicki, "Small Turbine for Solar Energy Power Package," United Nations E/Conf. 35/S/54 (Rome, 1961).

52. H. Tabor, "Large Area Solar Collectors (Solar Ponds) for Power Production," United Nations E/Conf. 35/S/47 (Rome, 1961).

53. Information which follows has been obtained from a number of different sources, including especially The Ford Foundation office in Rio de Janeiro, and is summarized here from unpublished materials on the economics of solar energy.

54. Note 34, supra.

55. P. C. Putnam, Op. cit., note 2, supra, p. 181.

56. A design for this purpose is given in A. Whillier, "Contribution to Solar House Heating - A Panel Discussion," Proceedings of World Symposium on Applied Solar Energy (Phoenix, Arizona, 1955) and in "Principles of Solar House Design," Progressive Architecture, Vol. 36 (1955), pp. 122-126.

57. E. Speyer, "Optimum Storage of Heat with a Solar House," Solar Energy, Vol. 3 (December, 1959), pp. 24-48.

58. See discussion by Speyer, Ibid., p. 29.

59. I. Oshida, "Uses of Solar Energy for Water Heating," United Nations E/Conf. 35/GR/13(S) (Rome, 1961), (rapporteur's report of session III.C.1).

60. The technologies represented here are described in many reports. For an early summary, see G. O. G. Löf, "Demineralization of Saline Water with Solar Energy," Saline Water Research and Development Progress Report No. 4, U. S. Department of the Interior (Washington, 1954). See also M. Telkes "Solar Still Construction," Office of Saline Water, Progress Report No. 33, U. S. Department of the Interior (Washington, 1959) and papers submitted in Session III-E, United Nations Conference on New Sources of Energy (Rome, 1961).

61. Estimate by U. S. Office of Saline Water, "Use of Nuclear Power for the Production of Fresh Water from Salt Water," op. cit., note 38, supra, pp. 82-86.

62. The magnitudes of prospective real cost increases are shown in R. A. Tybout, Op. cit., note 3, supra, Ch. 1.

63. Fuel export and import data are reported in United Nations Statistical Series J-7, Tables 3, 8, 9, 11 (serial publication).

64. See R. A. Tybout, Op. cit., note 3, supra, Table 6 and related discussion.

65. P. N. Rosenstein-Rodan, "International Aid to Underdeveloped Countries," Review of Economics and Statistics, Vol. 43 (May, 1961).

66. For a discussion of AEC policies to alleviate this problem, see Commissioner J. T. Ramey, "The U. S. Program for Advancing International Atomic Power," Nucleonics, Vol. 22 (July, 1964) and an interview with AEC Chairman G. T. Seaborg in the same issue.

ECONOMICS OF CONVERSION OF FOSSIL FUELS TO ELECTRICITY

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INTRODUCTION

The conversion of fossil fuels to electricity has traditionally been accomplished in the following sequence of processes: conversion to heat by combustion; conversion to mechanical energy through thermodynamic processes; conversion to electricity by dynamo-electric processes. Although more direct methods* are available, this paper will consider the economics of only this traditional conversion sequence. Since most of the electrical energy produced in the United States is generated by the Electric Utility Industry (91.5 percent in 1963), the economics will be discussed in terms of that industry. In other industries electricity is frequently a by-product of other thermal processes. The economics is special and diverse, and although it is of great significance to the industries involved, it is not fundamental to an over-all view of the conversion of fuel to electricity.

Figure 1 shows the historical trend of generating capacity of the electric utility industry in the continental United States and projections into the future. A band is used for the nuclear projection to cover the range of current forecasts by various industry groups. A significant point to be noted from this figure is that although nuclear capacity is expected to become increasingly important after 1970, fossil fired thermal capacity still shows impressive growth. This indicates that conversion of fossil fuels will for many years continue to be the major source of electric energy.

In the electric utility industry, power cost is commonly considered to consist of three components: fixed charges on investment, fuel, and operation and maintenance. The fixed charge component is actually the revenue requirement, expressed as a level percentage of first cost of plant to cover return, depreciation, Federal Income Tax, and other taxes and insurance. The fuel component is the product of conversion efficiency and fuel price and includes a charge for fuel inventory. Operation and maintenance includes the cost of labor, materials, and supplies. Table I illustrates the calculation of total power cost from a typical modern steam unit.

It should be noted that these costs would not be realized in an actual electric utility system because of the practical requirements of part load operation (which increases heat rate) and reserve capacity (which increases effective investment cost). These points will be discussed in more detail later.

The economics of energy conversion can best be discussed in terms of the actual apparatus that produces practical renditions of the processes involved. Accordingly, the discussion to follow will consider power cost components of: diesel engine plants, gas turbine plants, steam electric plants, and combination cycle plants.

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* The fuel cell accomplishes the conversion to electricity in a single step. Thermionic, thermoelectric and magnetohydrodynamic (MHD) methods require two steps: combustion to produce heat; and then direct conversion to electricity.

TABLE I

Investment, $/kw		110
Fixed Charges, mills/kwh (12% F.C., 80% Cap. Factor)		1.89
Operation and Maintenance, mills/kwh		0.25
Fuel Cost, Burn-up, mills/kwh (8800 Btu/kwh, 25¢/M Btu)	2.20	
Fuel Cost, Inventory, mills/kwh (90 days inventory at 10%)	0.07	
Total Fuel Component, mills/kwh		2.27
Total Power Cost, mills/kwh		4.41

PLANT INVESTMENT COMPONENT OF POWER COST

In order to translate plant investment into a power cost component, the fixed charge rate on investment and the capacity factor at which the plant operates, must be considered. Fixed charge rates vary from 10% per year to 15% per year, depending on the type of financing, i.e. the proportion of bonds, preferred stock and common stock; earnings permitted by the regulating commissions; rate of depreciation; and state and local taxes.

Internal Combustion Plants

Diesel-engine generator plants vary over a wide range in installed costs, depending on type of engine, speed, size and type of service for which intended. They may be installed for as low as $85/kw for sets designed for short time peaking service to as high as $200/kw for sets designed for heavy duty, full time base-load service.

Gas turbine generator plants also vary over a wide range in installed costs depending somewhat on rating but to a greater extent on the design efficiency. A relatively low efficiency simple cycle gas turbine plant for peaking service may be installed for as low as $70/kw, while a 2-shaft machine with regenerative cycle may be as high as $150/kw.

Steam Electric Plants

The installed cost per kw of steam electric stations has shown outstanding progress over the years, in spite of inflationary trends. This has been largely the result of the combined efforts of electric utility engineers, consulting engineers and equipment manufacturers who have displayed great courage and ingenuity in successfully applying ever increasing ratings. (Fig. 7) The downward trend in station costs per kw is also attributable to adoption of the unit system (1 boiler, 1 turbine-generator, 1 step-up transformer bank) and continued effort toward design simplification throughout the plant. Fig. 4 shows the downward trend in $/kw versus size, including the effect of typical steam conditions for the size of unit being considered. The indicated band will account for difference in site conditions, plant design concepts and local construction costs. Table II shows the relative installed costs of the major equipments in a typical steam-electric plant.

TABLE II

Site and Structure (Boiler)	16%
Steam Generator (Boiler) and Draft Equipment	25
Feedwater System and Piping	10
Turbine Generator	22
Condenser and Circulating Water System	8
Electrical Equipment	5
Coal Handling	6
Step-Up Transformer and High Yard Equipment	8
	100%

Other design factors influence the installed cost: a plant designed for oil or gas firing will reduce plant costs by $15 - $25 per kw; the range from an all indoor plant to the full outdoor design in the order of $5 - $10/kw; a wet type cooling tower where a moderate water supply is available adds $5 - $10/kw over the more conventional river, lake or ocean source; and a dry type cooling tower--for locations with minimum cooling water--will add $20 - $30/kw.

Steam Generators (Boilers)

Steam generator equipments offer the designer a real challenge to arrive at an optimized product after due consideration of many parameters. The greatest single unknown is the quality of fuel, in the case of coal, that will be burned throughout the life of the equipment and with which it is expected to meet the rated output. Over the years, the cost per unit of output has steadily decreased, primarily by taking advantage of the increased knowledge, gained through design and operating experience, pertaining to the many factors which can be utilized to increase the compactness of the equipment.

Higher temperatures and pressures permitted by modern metallurgy, reduce the required steam flow per kw of plant output. Increased knowledge of water treatment, of water circulation characteristics, of gas distribution in the pressurized furnace and the adoption of intermediate furnace walls, or twin furnaces, all contribute to compactness. At the higher pressures, use of forced circulation and elimination of the steam drum both contribute to reduction in materials.

Today, single steam generator equipments are being designed for flows approaching 8,000,000 #/hr--corresponding to a station output about 1200 mw.

Turbine Generators

The turbine designer has kept pace with the rapid increase in ratings, still showing a continued decrease in unit investment by arriving at designs with more and more compactness. A high rated turbine must pass high steam flow and the required orifice areas are obtained by longer buckets on larger wheels and in the lower pressure area of the turbine by providing multiple flow paths. These design features impose greater forces on the main casing flanges, greater centrifugal and bending forces on the wheels and buckets and greater spans between bearings. These and many other requirements are successfully met by the use of new alloy metals and design ingenuity--all resulting in higher outputs per unit of equipment.

High speed, 3600 rpm, turbines are applied for almost all modern high-pressure, high-temperature, steam conditions. Tandem turbines--one turbine and one generator--are today on order in ratings up to 700 mw. For still larger ratings the cross compound turbine is applied where two turbines are used in series in the steam path and each turbine has its corresponding generator. The high-pressure 3600 rpm turbine exhausts into a low-pressure 1800 rpm turbine where sufficient orifice area for the very high steam flows to the condenser is more readily obtained. Cross compound set ratings as high as 1130 mw are on order.

In nuclear fueled plants, where the steam conditions are appreciably lower than in fossil fueled plants, 1800 rpm tandem turbine-generator set ratings of 750 mw are on order.

While steam generators and turbines have been increasing in rating, the associated generators have also been keeping pace. As a first step, air has been replaced by hydrogen as a cooling medium in the generator casing. The latest development for the larger ratings was the introduction of the conductor-cooled generator where the rotor is designed so that hydrogen gas is in direct contact with the rotor conductors and where the armature bars are arranged for gas, oil or water to be in direct contact with the conductors for removal of heat loss. These design techniques have permitted spectacular increases in rating from the same physical size equipment.

Combined Cycle Plants

Some attention has been given to the combined gas turbine - steam turbine cycle where a conventional steam electric plant is essentially topped by a simple cycle gas turbine generator set, and the exhaust gases are used for combustion in the steam generator. Such a plant with output in the order of 250,000 kw is in successful operation, using gas as the fuel. Although this kind of plant requires added investment per kw, this is more than offset by the gain in efficiency. The widespread application of combined gas turbine - steam turbine plants awaits the development of successful coal firing.

Several years ago, when conventional units were in the 100,000 kw range and with heat rates 10,000 Btu/kwh or higher, plants with mercury cycle topping and heat rates of 9000 Btu/kwh received some interest. Since that time, however, the progress in heat rates of conventional cycles has reached the point where the mercury cycle practically cannot be justified because the heat rate gain is more than offset by the extra investment in plant equipment.

FUEL COMPONENT OF POWER COST

Although the inventory component of fuel cost is not negligible, it is sufficiently small that it can be ignored in a discussion of comparative fossil fuel conversion economics. The burn-up component, as noted earlier, is a function of efficiency and fuel price.

Diesel Engine Plants

The diesel engine in this country dates from about the year 1900. Since that time, the use of diesel engines has expanded tremendously, although for electric utility application, their use is limited by small unit size and inability to burn coal. Oil and gas fired diesel engines accounted for about 1.5 percent of total capacity in 1963. In recent years, there has been some application of small high-speed diesel engines for emergency and peaking service on large utility systems, but the major application is in base load service on small municipal systems. By the use of high cylinder pressures and temperatures, it is possible to obtain heat rates as low as 9500 Btu per kwh as indicated in Figure 2. As will be explained later, the heat rates in this figure are all based on the "higher heating value" of the fuel, and hence vary somewhat with the nature of the fuel.

Gas Turbine Plants

The first gas turbine used for electric power generation in this country was installed in 1949. Gas turbines are inherently simple machines of low first cost and their primary application in utility systems is for peaking and emergency standby service. Unit sizes are large enough to be practical for large utilities. Coal firing is not feasible, but gas turbines can handle a wide variety of oil and gas fuels. The major heat loss in the gas turbine cycle is the exhaust; and where no attempt is made to recover this heat, efficiencies are relatively low. Heat rates in the range of 14,500 - 16,500 Btu per kwh are typical, as shown in Figure 2. Where regenerators are used for exhaust heat recovery, heat rates as low as 13,000 Btu per kwh may be achieved. The use of higher firing temperatures (above 1600 F) will in the future reduce gas turbine heat rates.

Steam Electric Plants

The first central electric generating stations, built just prior to the turn of the century, consisted of boilers supplying saturated steam to reciprocating steam engines driving slow-speed generators. By 1910, the steam turbine was rapidly supplanting the reciprocating engine because of its greater simplicity and higher efficiency.

Figure 3 shows, schematically, a modern steam cycle. In considering the efficiency of such a cycle, it may be noted that the major source of boiler losses is in the heat contained in the gases discharged through the stack. In the 1920's, the introduction of economizers and air preheaters gave a substantial reduction in this loss by using the stack heat to preheat incoming air and feedwater. A second factor in boiler efficiency progress was the introduction of pulverized coal firing which greatly increased combustion efficiency. Other important developments have made it possible to maintain high efficiency at partial load. Some of these are control of gas flow by baffling and recirculation, and steam temperature control through de-superheating, differential firing, and burner angle control. Modern coal fired boilers have full load efficiencies of 90 percent or more.

Another major loss occurs in the condenser where heat in the turbine exhaust steam is rejected to the cooling water. This loss is substantially reduced by regenerative feedwater heating, accomplished by extracting steam from various stages of the turbine. This device has been universally used for over 30 years. A more recent cycle development is the use of reheat. After expanding partially through the turbine, steam is returned to the boiler and reheated to approximately initial temperature for re-entry to the turbine. Nearly all large steam plants going into service today incorporate this feature which improves the cycle efficiency 4 to 5 percent. A few plants have used a second reheat which provides an additional gain of about 2 percent.

Over the years, turbines have been designed in larger and larger ratings incorporating these cycle improvements, while at the same time, there has been steady improvement in turbine mechanical efficiency brought about by closer control of running clearances and leakages, advanced aerodynamic design of buckets and improved nozzle design.

Figure 2 shows today's net station heat rates for steam plants with steam conditions typical for the sizes shown. This ranges from 850 psig throttle pressure and 900°F temperature for the smaller units to 3500 psig, 1000°F initial and 1050°F reheat for the larger sizes. The approximate historical trend of best station heat rates is given in Figure 8.

Heading Value of Fuels

In the combustion of hydro-carbon fuels where water is a product, it is necessary to consider what are called the "higher" and "lower" heating values of the fuels. In practical thermodynamic machinery, the exhaust temperature is such that the product water is in the form of vapor. The heat of vaporization represents heat that, while produced in combustion, is not available to the machine or process. It has become customary to subtract this heat of vaporization from the total heating value of the fuel and refer to it as the "lower heating value". The total heat, as would be determined by bomb calorimeter, is called the "higher heating value". The thermal efficiency, or heat rate, of a generating plant thus depends upon which heating value is used in its determination. The situation is further complicated by the fact that the ratio of higher heating value to lower heating value is not the same for all fuels. Typical values are as follows:

Fuel	Ratio $\frac{HHV}{LHV}$
Coal	1.03
Oil	1.06
Natural Gas	1.11

In European practice, lower heating value is most commonly used; whereas in this country, higher heating value is the usual rule. An exception to this is in the diesel industry where HHV is used in quoting efficiency for oil fuel and LHV for gas fuel.

Operation and Maintenance Component of Power Costs

Diesel plants and gas turbine plants comprise relatively small ratings with resulting higher operation and maintenance costs than are experienced in steam electric plants. Furthermore, type of fuel, service conditions, and annual capacity factors vary widely. In general, however, typical costs for a diesel or gas turbine plant will be in the range of 0.5 to 5.0 mills/kwh for a capacity factor of 80%.

For steam electric plants, Figure 5 shows typical operation and maintenance costs for coal firing. Gas and oil fired plants have slightly lower costs.

Generation System Economics

From the foregoing discussion of investment cost, heat rates, and operation and maintenance costs for the different types of plants, it will be seen that a wide range in power costs per kwh is inevitable. Even considering only one type of generating plant, costs will vary considerably because of differences in fuel and construction costs in different parts of the country. But beyond these considerations of the cost of power generated in a single plant or unit is the question of total system cost which determines the impact of electric energy on the nation's economy.

The first factor that influences total system generating cost is the nature of the load. In a 24-hour period, the magnitude of load on a typical electric utility system varies through a two to one range. In a year this variation is three to one, or more. Figure 6 is a typical annual load duration curve. It shows that the top 20 percent of the load exists for only about 6 percent of the time. Generating cost for this component of load is very high because of the fixed investment charge which is distributed over only a few kwh. At the other extreme is the bottom 30 percent of the load which exists 100% of the time. This is the base load which may be generated at minimum cost. As noted earlier, part load efficiency of generating units is important because of the fluctuating nature of the load, and because excess capacity must always be kept in operation to provide a high degree of service continuity in the event of sudden equipment breakdown. In addition to this so-called "spinning reserve", it is necessary to have some capacity in cold standby for long-time outages, and to permit units to be withdrawn from service for maintenance and inspection. In general, electric utility systems have installed capacity representing 110 to 120 percent of anticipated peak load. This imposes an investment cost burden beyond that calculated for power conversion cost of a single unit.

The second factor influencing total system cost is growth. The industry has historically grown at the rate of about 7 percent per year. In the past, this growth, together with the shape of the load duration curve, has very neatly fitted the pattern of progress in generating unit efficiency so as to eliminate the problem of obsolescence: new efficient units could always operate at high load factor in the bottom of the load curve while older, less efficient units performed the short time peaking function. Today, the growth continues, and the load duration curve remains about the same, but progress in efficiency improvement has slowed. This gives an opportunity to apply special forms of peaking generation whose operating characteristics and low investment cost are ideally suited for the short duration peak load. Pumped storage hydro and gas turbines are beginning to find wide application for this bulk peaking service.

One might ask whether the introduction of nuclear power does not constitute the beginning of another technological cycle wherein progress in reducing fuel cost will again prove to be compatible with load growth and the shape of the load curve. This could be the case--but today there exist forms of peaking generation that were not available 60 years ago. And economic studies indicate that optimum system design must include peaking generation as well as the most advanced forms of base load units.

This brings up the third major factor in generation system economics: the emergence of new methods of system design analysis using simulation techniques in digital computers. It is now possible to analyze the performance and economics of alternate 20-year plans for generation system expansion with a high degree of accuracy and at reasonable cost. These methods are gaining wide acceptance and will perform an important service in keeping the future cost of electric power as low as possible.

In conclusion, there will be continued progress in the economics of converting fossil fuels to electricity, but probably at a less spectacular rate than in previous years. There is still opportunity for lower investment costs through design simplification and the application of still larger units. These same factors, together with automation, will result in lower operation and maintenance costs. Similarly, it is expected that modest improvements in conversion efficiency will be realized. Thus, there seems to be little doubt but that fossil fueled generating plants will continue to contribute in a major way to low total system generating costs in the future.

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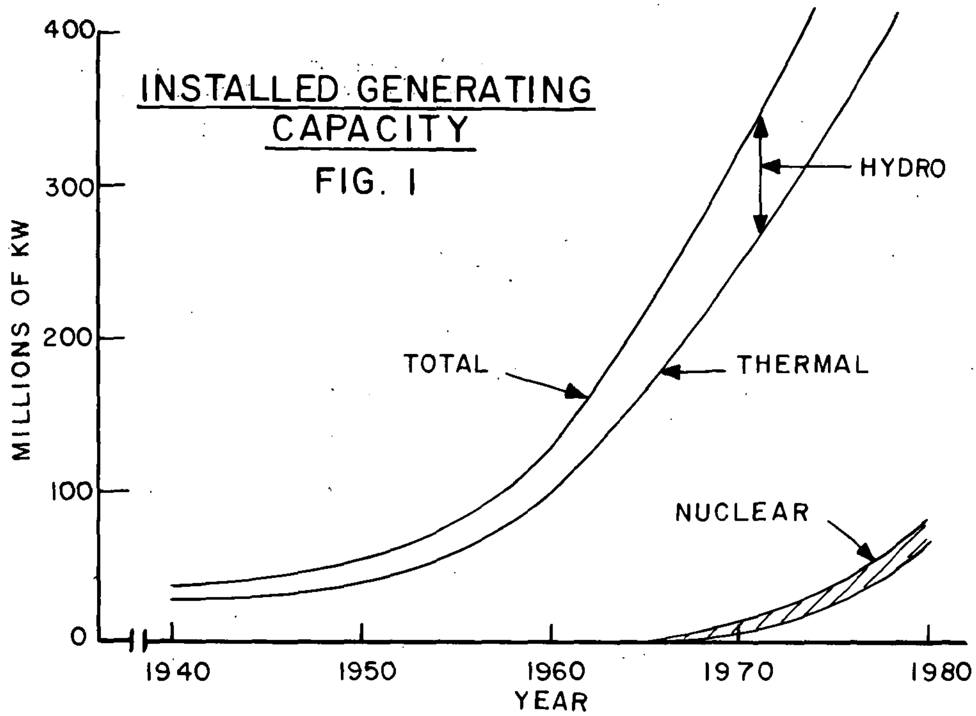
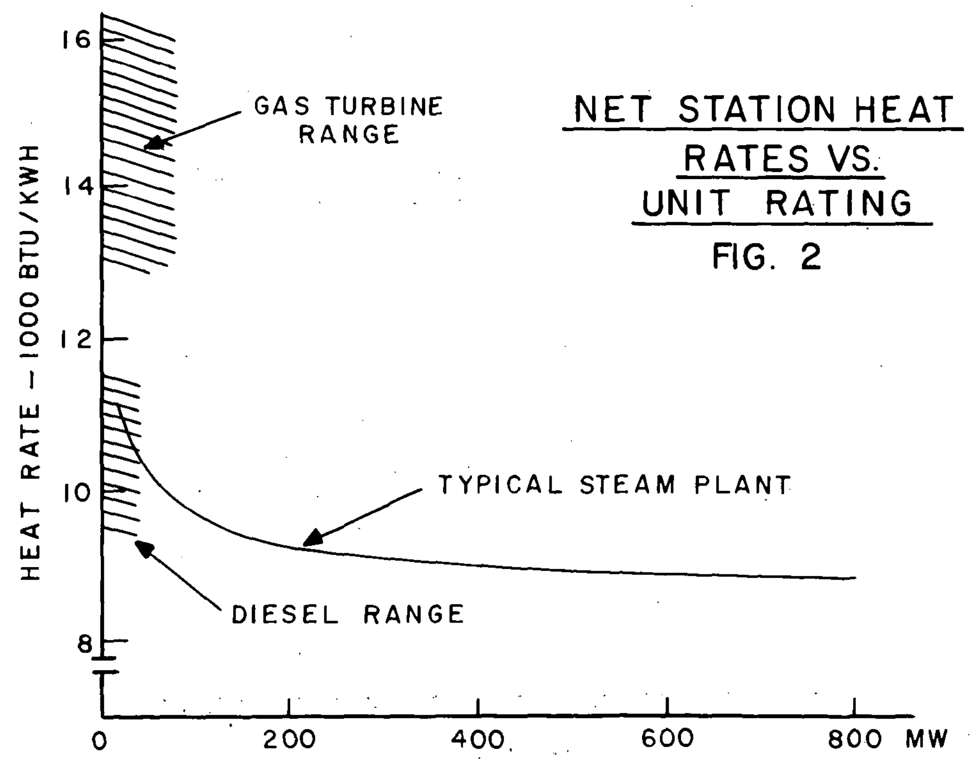


INSTALLED GENERATING CAPACITY

FIG. 1

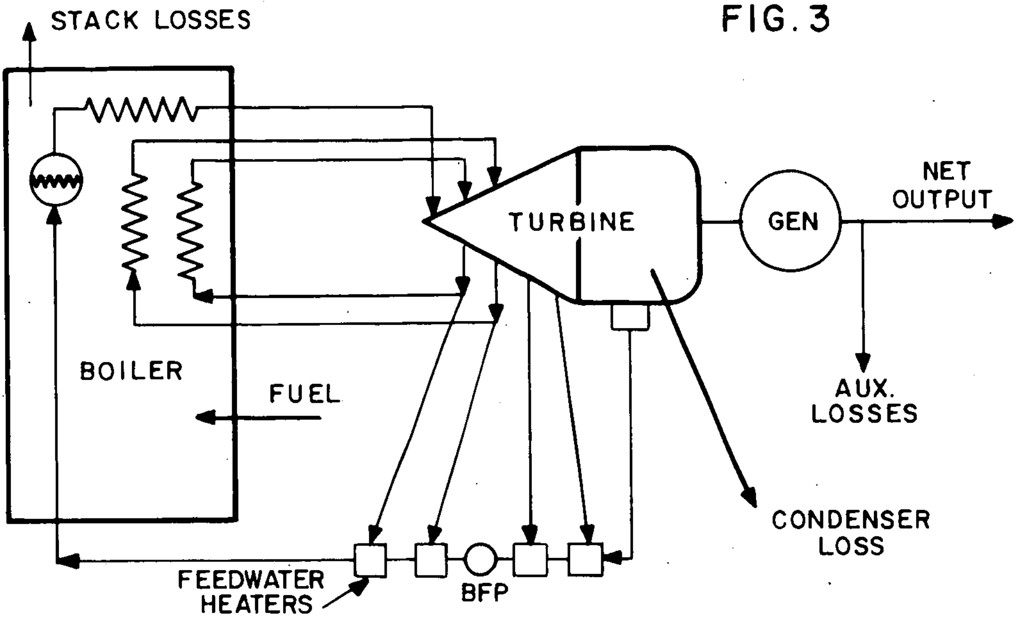


NET STATION HEAT RATES VS. UNIT RATING

FIG. 2

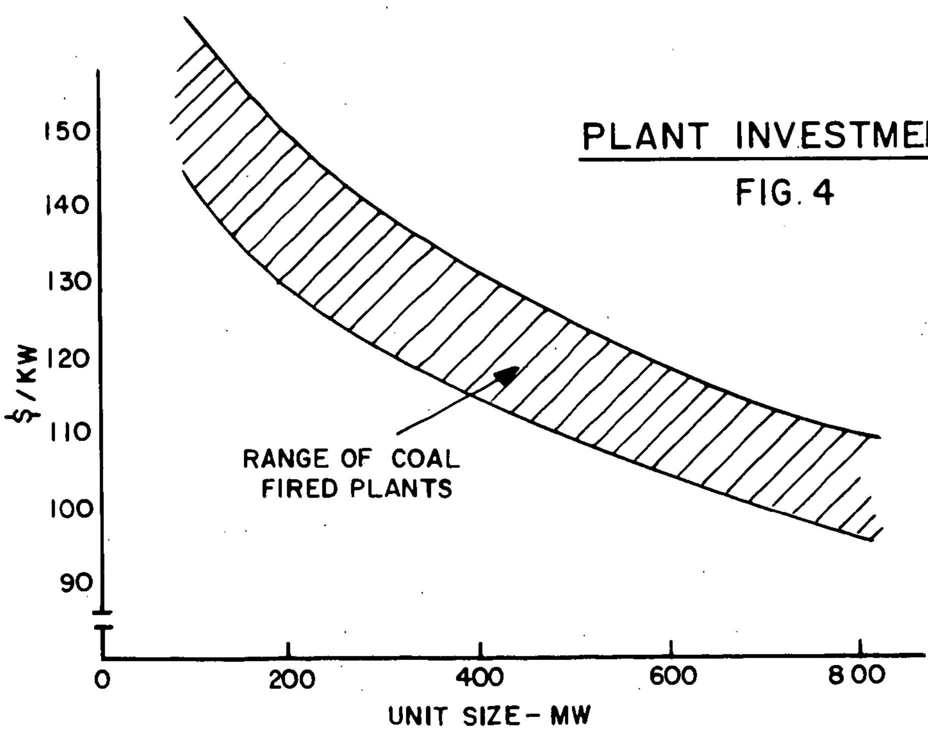
STEAM CYCLE DIAGRAM

FIG. 3



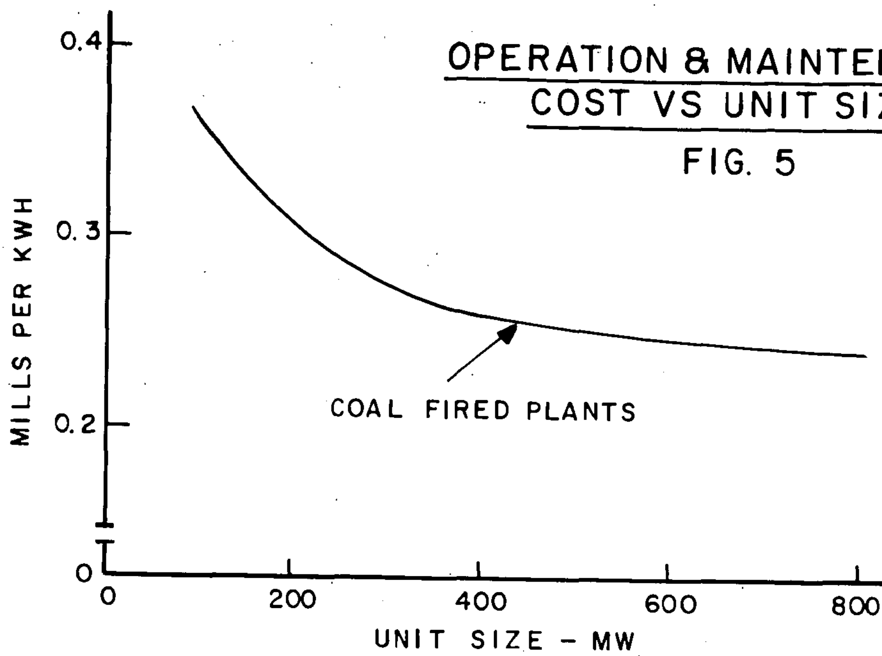
PLANT INVESTMENT

FIG. 4



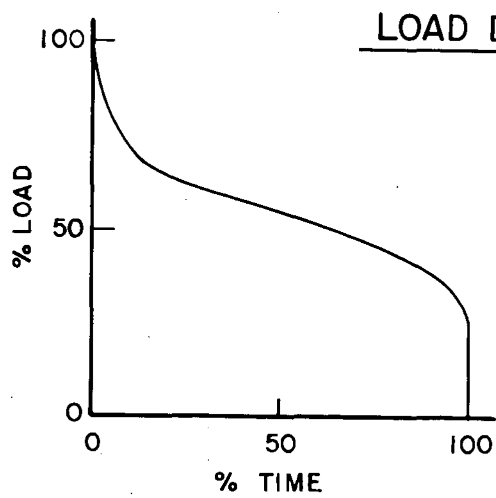
OPERATION & MAINTENANCE COST VS UNIT SIZE

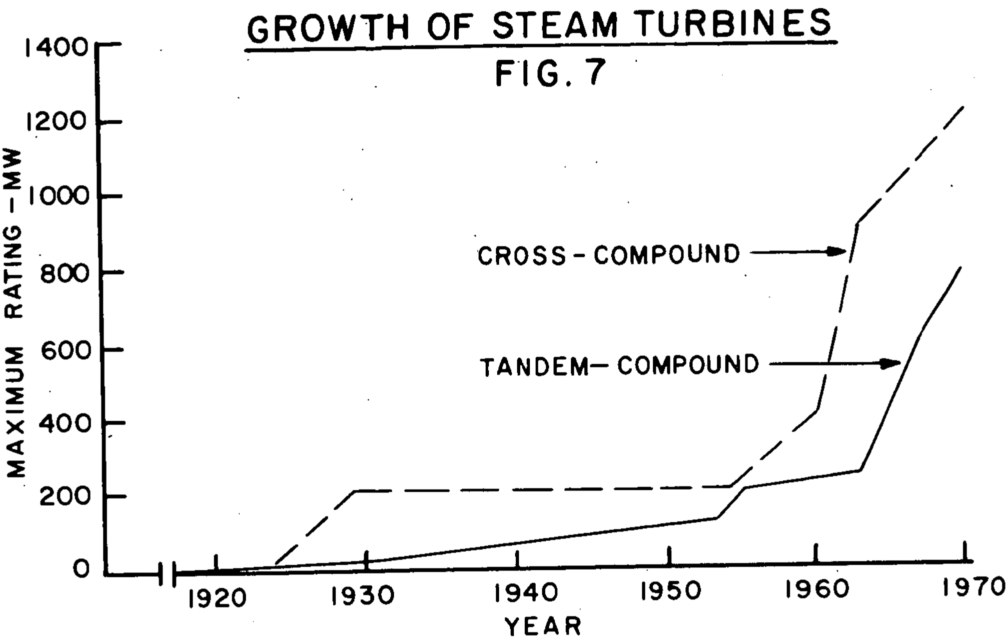
FIG. 5



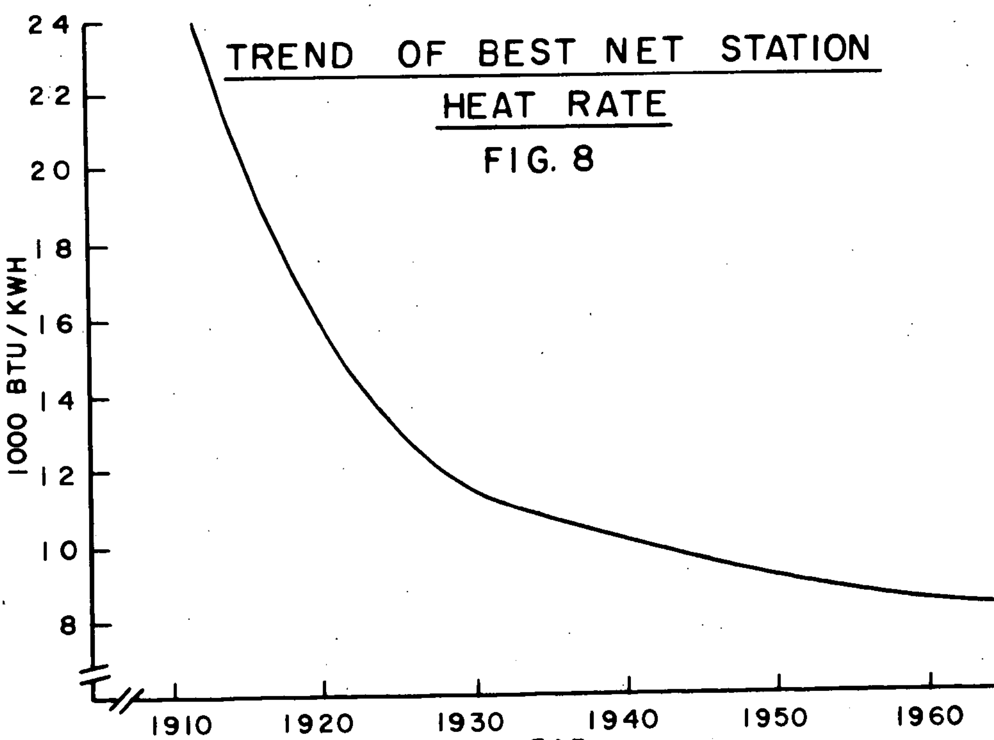
LOAD DURATION CURVE

FIG. 6





GROWTH OF STEAM TURBINES
FIG. 7
1400
1200
1000
800
600
400
200
0
MAXIMUM RATING - MW
CROSS - COMPOUND
TANDEM- COMPOUND
1920
1930
1940
1950
1960
1970
YEAR



TREND OF BEST NET STATION HEAT RATE
FIG. 8
24
22
20
18
16
14
12
10
8
1000 BTU/KWH
1910
1920
1930
1940
1950
1960
YEAR

NUCLEAR ELECTRIC POWER

Economics of the Conversion of Nuclear Energy to Electricity

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I. INTRODUCTION

This paper discusses the economics of producing electricity from nuclear energy. The economic data presented are intended to indicate the current and near-term situation in nuclear economics, without displaying undue optimism or pessimism. In addition, the subject matter are also for the purpose of providing you with a better understanding of the economics of nuclear power in general. The input data used in this paper are from a multitude of sources and in many cases, the data were subjected to interpretation by the author. I wish to also make the qualification that the specifics that go into determining the economic performance of nuclear electric plants are changing rapidly with time. Hence, you are cautioned that certain portions of this paper are subject to obsolescence and it is to be understood that the data and information presented represent the situation based on what we think we know today, as seen from the authors point of view. There are a number of factors currently prevalent in the field of nuclear power which make economic evaluations and analyses difficult. The nuclear industry is relatively new and a sufficient base of operations is just beginning to be established. There are reasons to believe that the size of the nuclear industry will increase rapidly with time. Several authoritative growth projections indicate that annual rates of nuclear fuel throughput and new plant construction will increase more than ten-fold in the decade 1970 to 1980. These factors introduce major complications in choosing realistic cost input data to use in economic computations. This is one of the primary reasons why estimates of future economic performance of nuclear electric plants vary widely.

In the U.S., economically competitive nuclear electric power has not yet been produced. However, it is expected that several large nuclear electric plants now under construction will demonstrate that they are competitive in their particular circumstances. It will be a few years however before this is borne out. Thus, one must look into the near future in order to speak of economic nuclear power. For this reason, it is important that the underlying technical, economic and operational assumptions which go into nuclear power cost estimates be spelled out with a reasonable degree of clarity. This paper attempts to provide a general appreciation of nuclear electric plant economics - it presents data on the currently estimated economic status and provides a general indication of what we might expect as more advanced reactor concepts are brought into being. In going about this endeavor, the following sequence of presentation will be followed:

- Current program
- Fuel cycles, flowsheet, material and energy balances
- Methodology of Economic Computations
- Specific Economic Estimates
- Analysis of Fuel Costs

Current Program

Historically, the AEC has carried out a broad base program of reactor development involving many reactor types. The scope of this past and current effort can be well appreciated by Table I which lists the nuclear plants presently committed, under construction or operable.

TABLE 1

NUCLEAR ELECTRIC PLANTS PRESENTLY COMMITTED, UNDER CONSTRUCTION, OR OPERABLE
(In the U.S.)

PRESSURIZED WATER	EMW NET	DATE CRITICALITY
Shippingport	100	1957
Yankee	175	1960
Indian Point	255	1962
Saxton	3	1962
San Onofre	375	1966
Malibu	463	1968
Haddam Neck	463	1967
BOILING WATER		
EBWR	4	1956
Dresden	200	1959
Big Rock Point	73	1962
Elk River	20	1962
Humboldt Bay	67	1963
Pathfinder	59	1964
Bonus	16	1964
La Crosse	50	1965
Oyster Creek	515	1967
Nine Mile Point	500	1968
WATER COOLED GRAPHITE MODERATED		
NPR	800	1965

GAS COOLED	EMW NET	DATE CRITICALITY
Peach Bottom	40	1965
EGCR	22	1965
SODIUM GRAPHITE		
Sodium Reactor Exper.	6	1957
Hallam	75	1962
HEAVY WATER		
Carolinas Virginia	17	1963
ORGANIC COOLED		
Piqua	11	1963
FAST SODIUM COOLED		
Fermi	61	1963
EBR-II	17	1963

TOTAL ABOVE (THROUGH 1968)

Operable by End 1964	1159 EMW
Under Construction	3228 EMW
TOTAL	4387 EMW

Data as of Dec. 31, 1964

Recently, the AEC has been reducing the number of reactor concepts under active development. The present AEC civilian nuclear power program is focused on the development of advanced thermal reactors and fast breeder reactors, leaving further improvement of the conventional light water reactors to industry.

The primary technical incentives for the development of these reactor concepts are listed in Table 2.

TABLE 2

TECHNICAL REASONS FOR ADVANCED THERMAL REACTORS

AND FAST BREEDER REACTORS

1. Achieve the timely introduction of advancing technology into the growing nuclear complex, with attendant cost reductions.

2. Reduce the requirement for fissile material mined from the ground, thereby extending the availability of nuclear resources.

3. Permit the use of higher cost nuclear fuel resources while still producing low cost energy, thereby expanding the resource base.

Fuel Cycles

Besides the various choices for structure, coolant and moderator combinations, nuclear reactors can operate with various combinations of fissile and fertile materials although certain reactor types are logically oriented towards particular fissile/fertile species.

The heavy elements of interest as nuclear fuels are shown in Table 3.

TABLE 3

NUCLEAR FUELS

Fissile	Fertile
Uranium 233	Thorium 232
Uranium 235	Uranium 238
Plutonium	

The naturally occurring nuclear fuels are thorium, uranium 238 and uranium 235. Thus, of the fissile isotopes, only U235 is naturally occurring, found in concentrations of 0.711 wt.% in natural uranium. The other two fissile isotopes, U233 and plutonium (isotopes 239, 240, 241 and 242) are produced through the capture of a neutron by thorium and uranium 238, respectively. The technology of the U235 - U238 fuel system is better established than that of other systems. Extensive fuel cycle development is in progress on the plutonium-uranium and the U233 - U235 - thorium systems. Studies are in progress on other combinations of fissile/fertile species.

Under certain conditions, it is possible to produce more fissile isotope than is consumed. This occurs when sufficient excess neutrons released during fission are captured in a fertile isotope, converting it to fissile. Such a process is referred to as "breeding". All reactors are inherently capable of converting fertile material to fissile. The extent to which they do this depends on a number of factors. These include the concentration of the fissile and fertile isotopes, the number of neutrons released per fission (a function of the isotope and the incident neutron energy), and the probability of the neutron released by fission being captured by a fertile isotope rather than being lost through leakage or capture in non-fuel materials. If the above conditions are favorable, the reactor can produce more fissile isotopes than it consumes. If the above conditions are less favorable, the reactor will still regenerate a certain fraction of the fissile isotope consumption.

Figure 1 indicates the overall flowsheet for a slightly enriched uranium fueled converter reactor with plutonium recycle. (See Figure 1, end of text).

Mass and Energy Balances - Reactor

Figure 2 indicates a mass and energy balance of a single irradiation cycle of a pressurized light water reactor, typical of some large plants currently under construction. (See Figure 2, end of text).

For this particular example, the heat was produced from the various isotopes as follows:

TABLE 4

Distribution of Heat Production by Isotope

Isotope	% of Heat Produced
U235	60
U238	5
Plutonium	35
	100

The conversion ratio, grams fissile produced per gram fissile consumed is 0.62.

Thus, in consuming 30.3 grams of fissile material by neutron absorption (25.7 grams of which fissioned), 18.1 grams of new fissile material was produced.

On an input-output basis, 30 grams of fissile material was fed to the reactor, 25.7 grams of material was fissioned and 19.1 grams of fissile material was discharged.

Mass and Energy Balance - Nuclear System

In providing the U235 for the reactor feed, the system flow sheet for this example looks about as shown in Figure 3 (See this Figure at end of text).

Thus, in this example, 4.1 Kg of fresh natural uranium is required to replenish the U235 consumed in each Kg of fuel throughput of the reactor. If the plutonium were recycled, the fresh natural uranium requirement would drop to around 2.4 Kg. Under this recycle condition the mass balance indicates that of the total natural uranium fed to the uranium enriching plant, about 1.1% of it actually is fissioned, most of the other 98.9% ending up in the enriching plant tails stream. This is one reason why we are working on advanced converters and breeders - to increase the fraction of mined uranium that is fissioned. Please note however that the 98.9% that is currently set aside is not lost. It can be reintroduced to the system at some future date as a fuel for breeder reactors.

I don't wish to leave the idea with you that in the above case example, there was not a significant quantity of heat released. The 24 MWD/KgU corresponds with releasing 900 million BTU per pound of uranium charged to the reactor.

II. METHODOLOGY OF COMPUTING ENERGY COSTS

The following discussion is not intended as a complete treatise on computing nuclear energy costs, but rather, it highlights the method employed in this paper.

Capital Costs

The capital costs set forth in this paper are intended to represent the total cost of acquiring an operable plant to a typical private utility company. These costs include plant equipment required through the point of supplying electric power to the main transformer but exlude the transformer cost and equipment beyond the transformer. This total cost includes the direct construction cost of the nuclear plant and includes indirect costs such as general and administrative expenses, architect engineer and nuclear engineering fees, plant startup cost, contingencies, escalation, taxes, and interest during construction. These indirect costs generally amount to 25 to 40% of the direct construction costs.

Fuel Cost

The individual items identified in a standard fuel cost presentation are generally as follows:

TABLE 5

Nuclear Fuel Cost

Direct Charges	M/KWH
Fabrication	XX
Uranium Consumption	XX
Spent Fuel Recovery (Chem. Processing & Shipping)	XX
Plutonium or U233 Credit	(XX)
Uranium Use Charge (if applicable)	XX
Subtotal, Direct	XX
Fixed Charges	
Working Capital	XX
Total Fuel Cost	XX

Most of the fuel costs given in this paper are for the condition where the nuclear fuel material is privately owned. For privately owned fuel, the item labeled "Working Capital", includes the investment charges in the fuel materials, and the uranium use charge entry is not used.

In addition, it includes other investments in the fuel cycle, based on a cash flow analysis and assuming that fixed charges on the fuel cycle investment are 10%/year on the net investment. A more complete discussion of fuel costing methodology is contained in a paper I presented at the Third United Nations International Conference on the Peaceful Uses of Atomic Energy, Geneva, Switzerland, August 31 - September 9, 1964, paper A/CONF. 28/P/247.

Operation, Maintenance and Insurance

Operation and maintenance costs are based on estimates of manpower, supplies and materials required to operate the reactor. Insurance costs are based on $60 million of third party liability insurance at a premium of $260,000/year plus $500 million federal indemnity at a premium $30 per thermal megawatt per year.

Fixed Charge Rate

Plant capital investment is charged against electricity generation through the use of an annual fixed charge rate. For example, the capital cost in dollars is multiplied by the fixed charge rate in %/year to give dollars per year. Dividing this by the KWH produced per year and converting dollars to mills, one gets the capital charges in M/KWH.

The annual fixed charge rate varies from one utility to another. For investor owned utilities it generally runs between 10 and 15%/year. For public utilities and cooperatives, it runs around 7%/year.

Capacity Factor

The plant capacity factor is the actual KWH production over a period of time divided by the KWH production that would have occurred if the plant had operated 100% of the time at its rated capacity; usually expressed as a percentage.

Nuclear electric plants have low incremental operating costs which favors operating them as base load plants. In this paper, an 80% capacity factor is generally used in the economic computations.

Total Generating Cost

The total energy cost is thus made up as follows:

TABLE 6

Total Generating Cost

Capital Charges	M/KWH
Plant	XX
Fuel Working Capital	XX
Fuel	XX
Operation, Maintenance and Insurance	XX
Total	XX

III. SPECIFIC ECONOMIC ESTIMATES

This section deals with the estimated economic performance of several types of nuclear electric plants. These include:

TABLE 7

Reactor Types Included

- Light Water Cooled and Moderated, Producing Saturated Steam (LWR)
- Heavy Water Moderated, Organic Cooled (HWOCR)
- High Temperature Gas Cooled, Graphite Moderated (HTGR)
- Sodium Cooled Fast Breeder Reactor (FBR)

For the light water reactors, data on capital costs is included in the discussion. For the other reactors, the discussion is limited to fuel costs.

A. LIGHT WATER REACTORS

As indicated earlier, most of our operating experience with nuclear electric plants is with the light water reactors - boiling and pressurized. The technology is to the point where manufacturers are making fixed price contracts with warranted plant and fuel performance available to utility customers.

1. Capital Costs

The capital cost of steam-electric plants, whether they use fossil or nuclear fuels, varies significantly throughout the country. While the size of the plant is important, there are many other factors which affect the capital cost. Foremost among these are the local site and labor conditions (including weather considerations) and the plant specifications desired by the individual customer. These and other lesser factors give rise to substantial differences in capital cost of electric plants. It is important that one appreciates that these differences exist. Nevertheless, specific plant capital cost data are of interest and if there are an adequate number of data points one can gain an insight of the cost situation.

Cost data for a number of light water nuclear electric plants are shown in Figure 4. (See this figure at end of text) The ordinate is the unit capital cost in $/KW (net) and the absicca is the station size. The date of completion (criticality) of each plant is in parenthesis. Two points are indicated for each plant, the points being interconnected by a straight line. The upper point is the unit cost of the initial warranted plant rating. The lower point is for the expected rating (or stretch rating). A few words regarding this overcapacity or stretch are in order. Since there is not yet a great deal of experience with nuclear power plant design and operation, the reactor manufacturers are deliberately conservative in selecting the values of the individual limiting conditions which go into determining a plants capacity. After the plant is placed into operation, the plant operator can set about actually establishing the plants capability. The over-capacity that can be realized will depend on several factors including the amount of conservatism incorporated in the reactor core design, the design versus warranted output and the capability of the steam piping and turbine generator system. The piping and turbine generator system can be closely designed to meet a certain design capability. It is the nuclear reactor portion of the plant where the design conservatisms are incorporated. Hence, in many plants now under construction, the piping and turbine generator side of the plant is being designed for higher power capability than the warranted reactor rating.

The dotted line on this slide is based on the price list published in the fall of 1964 by a large manufacturer of boiling water reactors. These costs are based on a turnkey built plant and I've added 20% to the published turnkey price to allow for customer costs. The customer costs generally run less than 20%.

Oyster Creek - Capital Cost

The very detailed analysis published in 1964 by the Jersey Central Power and Light Company for their Oyster Creek Nuclear Station has attracted a lot of attention, both in and out of the nuclear industry. To my knowledge, this is the most comprehensive analysis of the expected economic performance of a nuclear plant over a

30 year life ever published. The analysis was very detailed and most of the input economic and operational parameters were changing with time, to reflect what these people anticipated for the future. The salient capital cost data for this plant are given in Table 8.

TABLE 8

OYSTER CREEK NUCLEAR STATION

CAPITAL COST DATA

Single cycle boiling water reactor

Turnkey built plant

Total capital cost, including customer costs but excluding escalation: $66.4 million ($58.5 million excluding customer costs)

Plant Rating:

Initial guaranteed	515 MW (net)
Expected	640 MW (net)

Unit Capital Cost:

At Initial Rating	$129/KW (net)
At Expected Rating	$104/KW (net)

2. Fuel Costs

Fuel costs in a nuclear electric plant decline with time. This is due to several factors. First of all, the initial core loading of a reactor is usually designed for a lower goal exposure than is the replacement fuel. This is due to limits on holding down initial reactivity. The other reason is that the cost of the manufacturing operations will decline with time - partly due to technologic improvement and partly due to increased volume of business mentioned earlier. Recently the Atomic Energy Act was revised at the request of the AEC to permit private ownership of nuclear fuels. Prior to this legislation, ownership of the fuel was retained by the government and it was leased to customers. Carrying charges on leased material (usually called "use charges") are at the rate of 4-3/4%/year on the value of the material on hand.

With the new legislation, enriched uranium can now be either leased or purchased and after 1972, must be purchased. For reactor operators, the new legislation includes the following important milestones. As of January 1, 1969, the Commission will provide a uranium enriching service (fuel enriched through this service would be privately owned). As of Jan. 1, 1971, no additional enriched uranium will be distributed by the government by lease. Also, as of July 1, 1971, the guaranteed purchase of plutonium by the government will terminate. As of January 1, 1973, all material out on lease must be purchased.

Near Term Fuel Costs

The typical technical and economic bases and estimated near-term fuel cost of a light water reactor is given in Tables 9 - 11. The data used are intended to apply to a nuclear electric plant that could become operational around 1968-1969.

TABLE 9

Technical Bases for Fuel Cost

Large Light Water Reactor

(Heat Rate 10,900 BTU/net KWH)

	1st Core	Replacement Fuel
Initial enrichment, % U235	2.0	2.4
Discharge enrichment, % U235	0.83	0.85
Kg uranium discharged per Kg U charged	0.976	0.969
Plutonium discharged, grams per initial KgU		
Total Pu	6.3	7.3
Fissile Pu	4.4	4.9
Fuel Exposure		
MWD/KgU	16.5	22.0
Millions of BTU/KgU	1350	1800
Net eMWH/KgU	124	165
Fuel Specific Power, Thermal MW/MTU	15.5	18.5
Average Fuel Residence time in Core, Full power years	2.9	3.3

NOTE: U is uranium, MWD is thermal megawatt days of energy, MTU is metric tons uranium and eMWH is electric megawatt hours.

TABLE 10

Economic Assumptions for Fuel Cost

Large Light Water Reactor

	1st Core Average	Early Replacement Fuel
Fabrication Price $/KgU	100	85
Post Irradiation Shipping $/KgU	6	6
Natural Uranium Price, $/lb U_3O_8	8	6
Separative Work Cost, $/KgU	30	30
Cascade Tails Assay, % U235	0.253	0.281
Pu Credit, $/g fissile 1/	9	9
Chemical Processing, $/KgU	38	38
Ex-core Inventory Holdup Time, Years	1	1
Uranium Carrying Charges, %/year	4-3/4	10
Working Capital Charges, %/year	10	10
Plant Capacity Factor, %	80	80

1/ $9/gram is used in both columns since this is the estimated fuel value with U_3O_8 priced at $6/lb. In this connection, most of the plutonium produced by the first core is not discharged until after the assumed change in enriched uranium prices.

TABLE 11

FUEL COST

Large Light Water Reactor

80% Capacity Factor

	Cents per million BTU 1st Core	Cents per million BTU Replacement	Mills per net KWH 1st Core	Mills per net KWH Replacement
Direct Charges				
Fabrication	7.4	4.7	.81	.52
Uranium Consumption	8.5	7.6	.92	.83
Spent Fuel Recovery	3.3	2.4	.35	.27
Plutonium Credit	(2.9)	(2.4)	(.32)	(.27)
Uranium Use Charge	1.4	-	.16	-
Sub-total	17.7	12.3	1.92	1.35
Fixed Charges				
Working Capital	1.6	4.0	.18	.43 1/
Total Fuel Cost	19.3	16.3	2.10	1.78

1/ For the replacement fuel, the working capital charges are allocated as follows:

	M/KWH
Fabrication	0.13
Uranium Consumption	0.30
Spent fuel recovery	(0.07)
Plutonium Credit	0.07
	0.43

3. Operation, Maintenance, and Insurance Cost

For a 1,000 MW single unit nuclear electric plant, the annual operation and maintenance cost is around $1.6 million. This includes a total operating staff of around 75. The nuclear insurance would run something less than $360,000/year.

For an 80% plant capacity factor, these two items amount to:

O+M	0.23
Ins.	0.05
O+M+I	0.28 M/KWH

4. Total Generating Cost

The total generating cost of a typical 1000 MW light water reactor, based on the data presented above, would run about as shown in Table 12. These costs are representative of what one might expect of the early years of operation of a light water reactor entering service in the late sixties. It should be noted however, that these costs have not yet been demonstrated and it will be several years before we have the facts at hand to clearly back up these expectations.

TABLE 12

TOTAL GENERATING COST

1000 MW LIGHT WATER REACTOR NUCLEAR ELECTRIC PLANT
(after several years operation)
80% C.F.

	$/KW	$/KW-Yr.	¢/10^6 BTU	M/KWH
Capital Charges				
Plant (@ 12%/yr.)	120	14.4	-	2.06
Fuel (@ 10%/yr.)	29	3.0	-	0.43
Fuel	-	-	12.3	1.35
Oper. Maint. & Ins.	-	2.0	-	0.28
Total				4.1

NOTE: $/KW-Yr., ¢/$10^6$ BTU, and M/KWH are equivalents, not additive

B. ADVANCED THERMAL REACTORS

- Heavy Water Moderated, Organic Cooled -

- High Temperature Gas Cooled -

These two reactor concepts have the capability of breeding. For the present and near term, their operation will undoubtedly be optimized for minimum generating cost and this will lead to conversion ratios of less than unity. The current AEC program includes plans to construct a prototype thorium fueled high temperature gas cooled reactor and a uranium fueled heavy water moderated, organic cooled reactor. Both these prototypes will probably be around 300 MW in size. The AEC also plans to construct a seed blanket reactor prototype. This prototype is expected to demonstrate the interesting ability to breed in a light water reactor. This reactor concept is not discussed in this paper since it is outside my area of cognizance.

The fuel cost data presented below are idealized in the sense that it is assumed that fuel throughput rates are equivalent to an installed capacity of 15,000 MW (for the purpose of estimating processing charges). Also, it is assumed that the technology presently under development will be successful and that no real bottlenecks are encountered. So please bear in mind that these cost data are estimates and the technical characteristics of these reactors will not really be firmed-up until the prototypes have operated. At this point in time, the following data are to be considered as being speculative. They indicate what is potentially attainable if the development programs are largely successful; and if each reactor system is constructed in large quantity such as to realize large annual fuel throughput rates.

TABLE 13

BASES FOR FUEL COST

Large Heavy Water Reactor (Organic Moderated)

(Uranium Fuel Cycle - Sell plutonium)

Technical Bases	
Initial enrichment, % U235	1.20
Discharge enrichment, % U235	~0.05
Plutonium discharged, g fissile/KgU	4
Fuel Exposure	
MWD/KgU	20
10^6 BTU/KgU	1640
net eMWH/KgU	158
Net thermal efficiency, %	33
BTU/net KWH	10340
Fuel Specific Power, Thermal MW/MTU	24
Fuel residence time in reactor, full power years	2.2
Refueling	On-line
Economic Bases 1/	
Fabrication, $/KgU	40
Natural Uranium, $/lb U_3O_8	6
Separative work, $/KgU	30
Spent fuel recovery	30
Plutonium credit, $/fissile Gram	9
Working Capital Charges, %/year	10
Ex-core inventory holdup, years	1
Plant capacity Factor, %	80
Annual fuel throughput, MTU/year (for 15,000 MW)	660

1/ Fuel throughput rate and unit costs based on 15,000 MW installed capacity

TABLE 14

FUEL COST

LARGE HEAVY WATER REACTOR NUCLEAR ELECTRIC PLANT
(Equilibrium Cycle)
80% C.F.

	Cents per million BTU	Mills per net KWH
Direct Charges		
Fabrication	2.4	0.25
Uranium Consumption	3.4	0.35
Spent Fuel Recovery	1.8	0.19
Plutonium Credit	(2.2)	(0.23)
Sub-total	5.4	0.56
Fixed Charges		
Working Capital 1/	1.2	0.12
Total Fuel Cost	6.6	0.68

NOTE: Charges for heavy water (investment and losses) amount to about 1.9¢/10^6 BTU or 0.2 M/KWH. Charges for organic makeup amount to about 1¢/10^6 BTU or 0.1 M/KWH. Thus the fuel cost plus special charges on heavy water and organic amount to about 8.8¢/10^6 BTU or 0.91 M/KWH.

1/ The working capital charges are allocated as follows:

	M/KWH
Fabrication	0.05
Uranium Consumption	0.07
Spent fuel recovery	(0.04)
Plutonium Credit	0.04
	0.12

TABLE 15

BASES FOR FUEL COST

High Temperature Gas Cooled Reactor
(Thorium Fuel Cycle - recycle U233)

Technical Bases

Initial enrichment, % U235 + U233 in U + Th	3.1
Discharge enrichment, % U235 + U233 in U + Th	2.5
Kg U + Th discharged per Kg charged	0.94
Fuel Exposure	
MWD/KgU + Th	52
10^6 BTU/KgU + Th	4260
Net eMWH/KgU + Th	550
Net Thermal efficiency, %	44
BTU/net KWH	7760
Fuel specific power, thermal MW/MTU + Th	29
Fuel residence time in reactor, full power years	5
Fraction of core replaced per refueling	1/6

Economic Bases 1/

Fabrication, $/KgU + Th	110
Natural uranium, $/lb U_3O_8	6
Thorium, $/lb ThO_2	5
Separative work, $/KgU	30
Spent fuel recovery, $/KgU + Th	110
U233 value, $/g U233	11
Working capital charges, %/year	10
Ex-core inventory holdup, years	1
Plant capacity factor, %	80
Annual Fuel throughput, MTU + Th/year (for 15,000 MW)	190

1/ Fuel throughput rate and unit costs based on 15,000 MW installed capacity.

TABLE 16

FUEL COST

LARGE HIGH TEMPERATURE GAS COOLED REACTOR NUCLEAR ELECTRIC PLANT
(Equilibrium Cycle)
(80% C.F.)

	Cents per million BTU	Mills per net KWH
Direct Charges		
Fabrication	2.6	.20
Uranium Consumption	1.8	.14
Spent Fuel Recovery	2.6	.20
Sub-total	7.0	.54
Fixed Charges		
Working Capital 1/	5.0	.39
Total Fuel Cost	12.0	.93

1/ The working capital charges are allocated as follows:

	M/KWH
Fabrication	0.07
Uranium Consumption	0.39
Spent Fuel Recovery	(0.07)
	0.39

According to these data, the HWOCR has a projected fuel cost of about 0.7 M/KWH and the HTGR about 0.9 M/KWH. The HWOCR has some extra charges for heavy water and makeup of organic coolant degradation that do not apply to the HTGR. The sum of these extra charges -- based on 10%/year investment charges on heavy water, 0.5% heavy water loss per year, organic makeup rate of 4000 lbs. per eMW per year; and costs of $20/lb heavy water and 17 cents per pound organic -- amount to 0.2 M/KWH on the heavy water and 0.1 M/KWH on the organic. Therefore, the sum of fuel cost plus special material charges for the HWOCR is about one M/KWH. Thus the HWOCR and HTGR are very close together on the basis of fuel cost plus special material charges.

The light water reactor described previously, if evaluated on the basis of computing fuel cycle unit costs according to the throughput rate for 15,000 MW, has an estimated fuel cost (direct plus fixed charges) of 1.4 M/KWH.

C. FAST BREEDER REACTORS

Most of the effort on high gain breeder reactors centers around the sodium cooled fast breeder reactor, fueled with plutonium. This reactor offers promise of attaining a reasonably high breeding gain and a reasonably short doubling time.

It appears that for many years to come, the requirement for natural uranium mined from the ground will be determined by the amount of fissile material required for inventory buildup and fuel makeup. A high gain breeder reactor offers the interesting prospect of eventually making the nuclear complex self-sufficient on fissile material at which time the system can be sustained on the fertile fuels - U238 and thorium. This will permit utilization of most of the latent energy of fission contained in our nuclear resources.

The design characteristics of fast breeder reactors are less well defined than the reactors previously discussed. However, a number of conceptual design studies have been made so there is some indication of how they may perform. The following tables provide preliminary estimates of the bases for and resulting fuel cost of a fast breeder reactor.

TABLE 17

BASES FOR FUEL COST

SODIUM COOLED FAST BREEDER REACTOR NUCLEAR ELECTRIC PLANT
(1100 eMW net, 44% net thermal efficiency)

	Core	Blanket	
		Axial	Radial
Technical Bases			
Power, thermal MW	2170	35	295
Initial Loading, MTU + Pu	23.7	8.0	57.1
Initial concentration, Kg fissile Pu/Kg (U+Pu) in	0.156	0	0
MT(U+Pu) discharged per MT(U+Pu) charged	0.893	0.995	0.992
Discharge concentration, Kg fissile Pu/Kg (U+Pu) out	0.141	0.020	0.048
Fuel Exposure, MWD/initial KgU+Pu	100	4.8	7.6
Fuel Residence Time, full power years	3.0	3.0	4.0
Fuel fraction replaced per refueling	1/6	1/6	1/8
Economic Bases			
Fabrication, $/KgU+Pu	190	190	50
Spent fuel recovery, $/KgU+Pu	120	55	40
Plant Capacity factor %	----------	80	----------
Plutonium Credit, $/fissile gram	----------	10	----------
Working Capital Charges, %/year	----------	10	----------
Ex-core inventory holdup, years	----------	1.0	----------

TABLE 18

FUEL COST

SODIUM COOLED FAST BREEDER REACTOR

	Core	Blanket	Total
	------------	M/KWH	------------
Fabrication	0.16	0.12	0.28
Pu Consumption	0.27	(0.75)	(0.48)
Spent Fuel Recovery	0.10	0.07	0.17
Subtotal	0.53	(0.56)	(0.03)
Working Capital	0.56	0.24	0.80
Total	1.09	(0.32)	0.77

IV. ANALYSIS OF FUEL COST

This section discusses several important aspects of nuclear electric plant fuel costs.

Uranium Pricing

In the U.S., enriched uranium is produced by the gaseous diffusion process. If one makes a few simplifying assumptions, the cost-enrichment relationship is as follows:

$$C\ (X_i) = F\ (X_i)\ C_f + \Delta(X_i)\ C_\Delta \qquad \text{.............(1)}$$

Where: $C(X_i)$ = Unit cost of uranium of enrichment X_i, \$/KgU

$F(X_i)$ = Kg natural Uranium feed required to produce 1 Kg of uranium at enrichment X_i.

C_f = Unit cost of natural uranium feed to the diffusion plant, \$/KgU as UF_6.

$\Delta(X_i)$ = Separative work required to produce 1 Kg of uranium of enrichment X_i from natural uranium, Kgs U

C_Δ = Unit cost of separative work, \$/KgU

The feed requirement per Kg of product is:

$$F(X_i) = \frac{X_i - X_w}{X_f - X_w} \qquad \text{.............(2)}$$

Where: X_i = product material enrichment

X_w = diffusion plant tailings enrichment

X_f = natural uranium enrichment (0.711%)

The separative work requirement is:

$$\Delta(X_i) = \phi(X_i) + W\phi(X_w) - F\phi(X_f)$$

Where: $\phi(X_j) = (2X_j-1)\ \ln \frac{X_j}{1-X_j}$

W = Kgs diffusion plant tailings per Kg product

$F = F(X_i)$ defined previously

For any particular ratio of feed to separative work cost, there exists a certain optimum tailings enrichment which will result in minimum product cost (any product enrichment). The tailings enrichment, X_w, is determined by taking the first derivative of the cost equation (1) with respect to X_w, setting it equal to zero, and solving for X_w. That is, solve for X_w in the equation:

$$\frac{dC(X_i)}{dX_w} = 0 \qquad \text{.............(4)}$$

The current USAEC schedule of charges for enriched uranium is based on a natural uranium feed charge of \$23.5/KgU as UF_6 and a separative work charge of \$30/KgU. For this ratio of feed to work cost, the optimum tailings enrichment computed from equation (4) above is 0.253% U235 in Uranium.

Makeup of Fuel Cost

Table 19 indicates the makeup of the direct fuel cost of the light water reactor described in Table 12, but on a plutonium recycle mode of operation. The costs are allocated to the discrete production operations which were previously set forth in the flowsheet of Figure 1.

TABLE 19

DISTRIBUTION OF FUEL COST COMPONENT CHARGES

Light Water Reactor with Plutonium Recycle
(See Table 9 for Design Data)

	%of Direct Fuel Cost
Mining, milling, refining	20
Conversion U_3O_8 to UF_6	2
Enriching	23
Fabrication	36
Spent Fuel Recovery	19
	100

NOTE: This cost allocation compares with the flowsheet shown in Figure 1.

Minimized Fuel Costs

One of the interesting characteristics of nuclear fuel cycles is that there exists a certain optimum fuel exposure to obtain minimum fuel cost. This is mostly due to the increase that results in nuclear fuel investment charges as the design fuel exposure is increased. This in turn is due to the increased fissile loading required to attain high fuel exposures. The optimum fuel exposure depends on the combined effect of all of the individual cost inputs to the fuel cost computation.

A typical set of fuel cost versus fuel exposure curves are given in figure 5 (see this figure at end of text).

V. CONCLUSIONS

The nuclear industry is relatively new and is just beginning to show positive signs of getting underway. Much research and development is in progress. These conditions contribute towards causing specific levels of economic performance of nuclear electric plants to change rapidly with time. Thus, one must be closely connected with the nuclear power field in order to keep abreast of the situation.

Since 1960, twelve nuclear electric plants have entered service but only one of them can be called reasonably large. Small nuclear plants demonstrate technology well, but because they are small, cannot demonstrate economic competitiveness. Thus, we are in a position today where we think nuclear plants can be built which will be economic but we don't have any in hand at the moment. In the period 1966 through 1968, five large nuclear electric plants are scheduled to enter service. It will be most interesting to closely follow their progress and performance to see if our predictions will indeed be realized.

Figure 1

Uranium Flowsheet
Nuclear Electric Plant and Supporting Operations

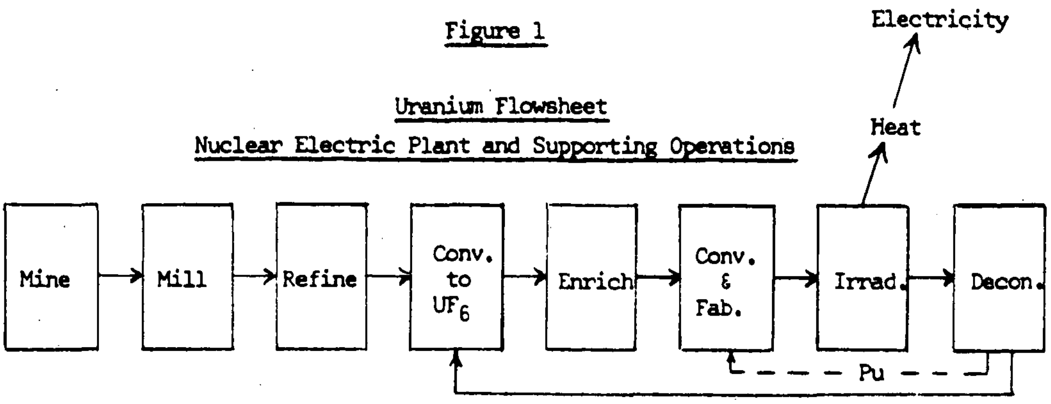
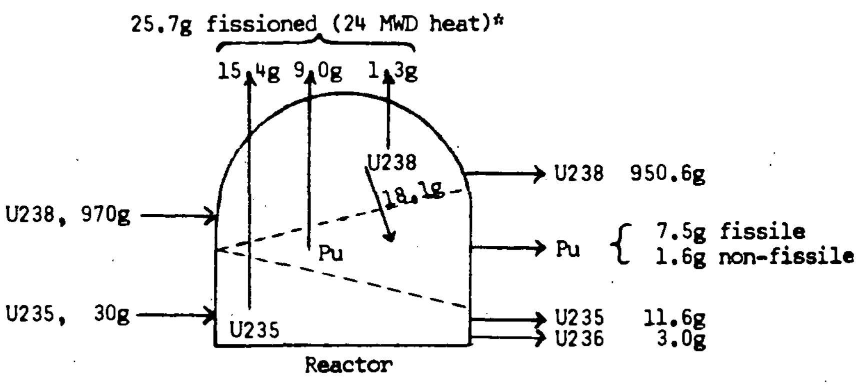


Figure 2

Mass and Energy Balance Around Reactor
(one irradiation cycle)



* 0.023 grams mass converted to energy ($E=MC^2$)

Figure 3

Mass Balance Around Nuclear System
(Non-Pu Recycle)

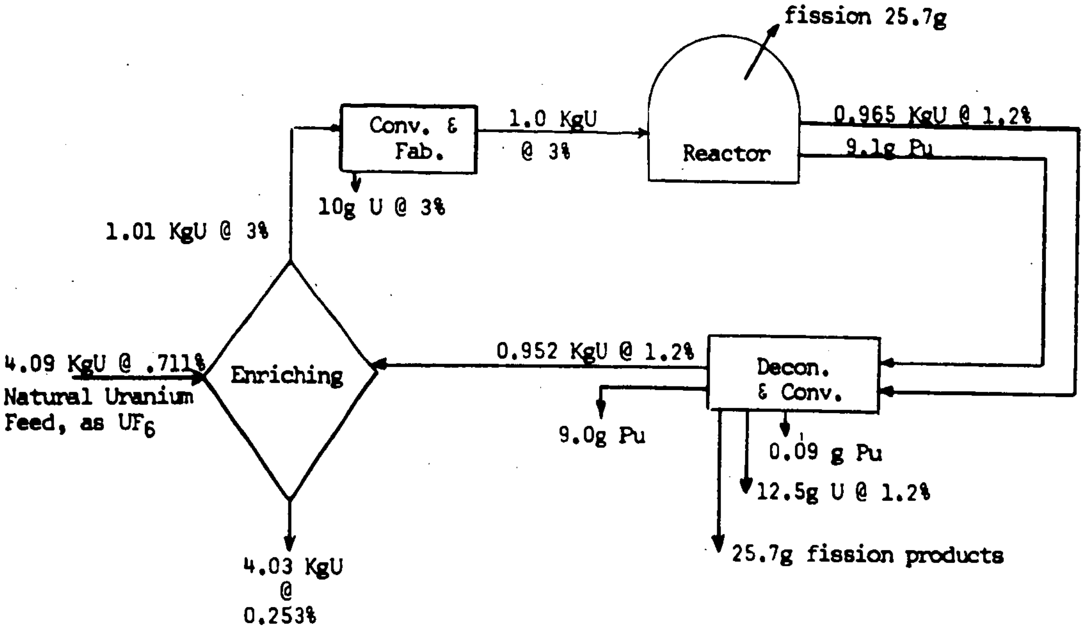


Figure 4

Trends in Capital Cost
Light Water Nuclear Electric Plants

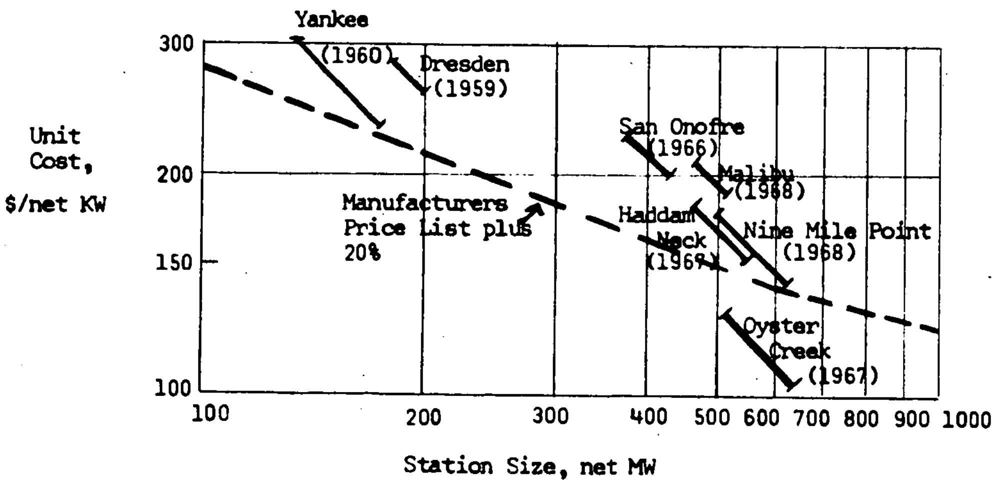
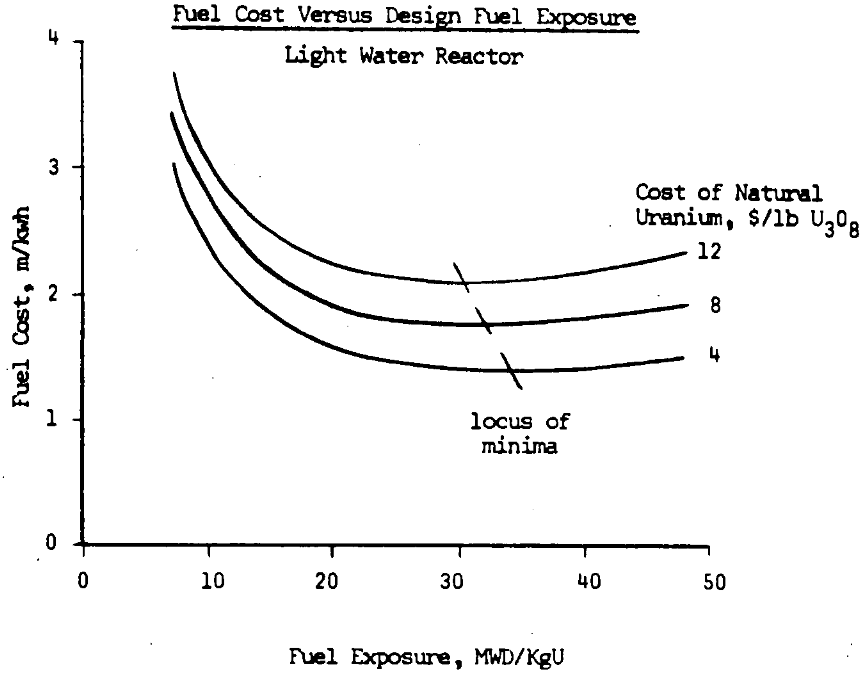


Figure 5

ILLUSTRATIVE EXAMPLE

Fuel Cost Versus Design Fuel Exposure

Light Water Reactor



UNCONVENTIONAL ENERGY CONVERSION METHODS

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Introduction

The recent accomplishments in the field of direct energy conversion are receiving increased attention in the power industry since the potential rewards of lower costs are substantial. There would appear to be merit in a mutual consideration by the chemical and power industries of the possibilities and advantages of lower cost power in the chemical industry to be obtained through lower generation costs using new methods of energy conversion, and, of perhaps equal importance, through better and more effective utilization of the present facilities of large power systems.

Electric power companies have always engaged in system planning -- to predict future production and system requirements, and to apply new ideas and methods to reduce costs. Essential to any plan is the selection of generation methods producing the lowest overall cost, since this is the base to which all other costs are added. Consequently, it is important that we be actively engaged in and intelligently informed on these new system concepts so that they may be applied to our mutual advantage.

In considering the application of new methods of electric power generation, their effect in accelerating improvement of conventional methods should not be overlooked. Economic comparisons must recognize that present methods have been improved and costs reduced, and these methods will be further improved beyond what was anticipated earlier, because of the competition from new fields of technology, from improved efficiencies of conventional methods, or from other factors such as resulted from the unit-train delivery of coal to power plants.

Another example of a change which is beginning to have an important effect on power costs is the advent of commercially competitive nuclear plants. While nuclear power provides only a small part of today's generation, it promises to assume a significant part of the new capacity installed in the next ten or fifteen years. Nuclear reactors, even with present design, are now economic in some areas having high fuel cost, and in the near future will probably become competitive in all but the lowest cost fuel areas. Several of the advanced methods of power generation can be used to good advantage with a high-temperature nuclear reactor. Since such combinations can offer an important improvement in present nuclear cycle efficiency, their development may be accelerated along with nuclear power development.

In order that we may have some appreciation of the magnitude of the rewards we are talking about, a discussion of only one of the many items affected may be in order; namely, the fossil fuel bill of the investor-owned companies. The investor-owned companies in the United States at the present time spend about $1.6 billion a year on fuel. This will increase substantially in the years ahead because of increasing demands for energy. Figure 1 shows the Edison Electric Institute's estimate for power production by investor-owned companies for the next fifteen years.

Efficient as our present power plants are, there is still promise of developments ahead in conventional generating equipment and systems. Figure 2 shows the trend in net station efficiency for fossil-fuel fired plants, from 1940 to 1960, and a projection to 1980. As indicated on this figure, developed in essence by W. D. Marsh of the General Electric Company, increases are likely to be achieved through the use of higher pressures and temperatures. There are other paths to increased efficiency, notably through the use of combined gas turbine-steam cycles, and possibly binary vapor cycles, using steam and mercury, or perhaps one of the alkali metals, potassium for instance.

Accordingly, the curve for the years 1970 to 1980 indicates a range of values to accommodate the possibility of achieving some of these cycles economically. It should be recognized that technically some of them can be built now, but either the economics or the operating complexities are such that they are not practical for average use at the present time. Figure 2 also illustrates the fact that the new methods of power generation promising higher efficiencies have a continually changing target to meet, one that becomes more difficult to achieve as the technology of conventional systems improves. For example, the probable improvement in the power field is indicated in Fig. 3. The table shows a substantial decrease in energy cost over a seven-year period and also indicates that nuclear power must be considered for any future capacity installations.

From the foregoing, it can be demonstrated that for an improvement in efficiency of 15 percent, for example, a fuel savings alone of about $200 million per year would be achieved by the year 1980, for only the new capacity installed. Such improvement is technically attainable, and within possible economic feasibility for several of the new methods of power generation. By providing lower cost power, it is hoped that these new methods will encourage developments of substantial new markets for the chemical industry.

The increasing demand for products from our two industries will require that larger sizes of equipment be installed. According to the Edison Electric Institute's forecast for the production of electrical energy for 1980, the power industry must either install three times as many generating units as it is today, or install the same number of units but three times the size of today's units, or some optimum combination thereof. It is probable that the installation of 1000 mw or 1500 mw generating units will not be an uncommon occurrence in the 1980s. The chemical industry can presumably expect to increase in a similar manner.

The increasing amount of "total energy" -- heat and electrical -- required to meet the increasing demands in the chemical industry will dictate some new and perhaps "unconventional" approaches when reviewing future production costs. The cost of this "total energy" would be considerable if produced by the chemical industry in smaller units, but could be at a relatively lesser incremental cost in the increased sizes which, it is predicted, will be installed by the power industry. Figure 4 is shown to illustrate the trend in reduction in capital costs and station net heat rate associated with the increase in size of generating units. These data are from Electrical World's 13th Steam Station Cost Survey, as published October 7, 1963. The chart is already outdated because station costs are even now 10 to 20 percent lower than shown in this chart for sizes of 500 mw and larger.

By taking advantage of the "total energy" supply concept, mutual advantages are possible. As a start in this direction, The Detroit Edison Company has purchased the power and steam generating facilities of two major chemical industries in its service area -- Wyandotte Chemicals Corporation and Pennsalt Chemicals Corporation. It is the philosophy of Detroit Edison that supplying of energy is its business and that it should be able to do so in a large system at a saving as compared to isolated smaller plants. The capital which the chemical industry would forego in investment for power and steam equipment could, it would seem, be put to more productive use in the expansion of product manufacturing facilities. Two of Detroit Edison's large chemical customers have agreed with this philosophy. I believe that there are mutual benefits to be gained by closer cooperation between our two industries. For instance, further benefits to both the chemical and power industries may be possible if use can be made of the power industry's large off-peak generating capacity.

New Concepts

As indicated before, several of the new methods of power generation offer promise of commercial application to power system generation as a means of reducing production costs. The economic and technical status of the more promising of these are discussed in the following.

Thermoelectric

Of the four advanced concepts for power generation which are receiving most attention, the thermoelectric generator seems least likely to significantly affect the power industry. Thermoelectricity is beset with materials problems. The high interest in the late 1950s was generated by the development of semi-conductors and doped semi-conductors which produced a considerable increase in thermoelectric efficiencies. The initial enthusiasm has abated somewhat as no significant materials advance has appeared since then. However, small thermoelectric power generators have been built and operated. Home and office heating and cooling units involving thermoelectric devices are available at a price. Thermoelectric devices operating on hydrocarbon fuels have been developed for use primarily where low-wattage, continuous trouble-free operation is needed in remote areas. Thermoelectric generators fueled with radioisotopes are being used to power navigation buoys, remote unattended weather stations, as well as military and space applications.

Thermoelectric generation would still seem to finds its greatest application as a power consumer rather than as a power producer. For example, Fig. 5 was reproduced from a recent Sears, Roebuck and Co. brochure which offers "Coldspot Thermoelectric" buffet bars with a price range of $395 to $495. They also offer the working unit alone for $295 to use in some stationary spot in the home or office. Push buttons switch the unit from "keep-hot" to "keep-cool" or vice versa. Dials regulate the temperatures from below freezing to above 150 F. Others are offering this same or similar equipment.

Economic studies seem to indicate that thermoelectric generation will be limited in size and will be useful only in special applications. By 1980, capital costs may be reduced to the range of $200 to $500 per kilowatt of installed capacity. This could not be considered as economic for large scale power generation.

Thermionic

Thermionic generation is of significance to the power industry because of its adaptability to bulk power generation, particularly in central station reactor power plants. Reports from the large research and development effort indicate that the adaptation to space uses is on schedule, although the vehicles and missions which would require the 50-1000 kw nuclear-thermionic power supply may be further in the future than indicated heretofore. Figure 6 illustrates a space application of thermionic power.

An attractive commercial application of the thermionic converter is as an in-pile device for a nuclear reactor. Because the required emitter temperature is in the order of 3000 F, uranium carbide or a modification of it has desirable properties for such service. Consequently, it appears most practical to combine a thermionic topping device as part of a nuclear reactor. Since the efficiency of thermionic converters may ultimately reach 15-20 percent, a thermal cycle in which such devices are superimposed on a conventional cycle may significantly increase future plant efficiencies. However, other developments, such as nuclear superheat, may reduce the incentive for thermionic topping of reactors producing saturated steam. Perhaps equally important is the possibility of significantly increasing reactor capacities without commensurate increases in physical size or costs. However, at present, it appears that economics will not favor commercial use of thermionic devices within the next ten years.

Magnetohydrodynamics

The commercial generation of power by magnetohydrodynamics, more conveniently referred to as MHD, appears to be associated with materials and costs. It is only fair to acknowledge that there is a difference of opinion in the industry as to the future of MHD in the United States. A combined MHD and steam cycle, in which gas from the MHD generators would be discharged to a steam-generator turbine-generator system, may prove in time to be economically feasible. As this would involve an open-cycle coal-fired MHD unit, problems are encountered with its molten coal ash, and high-temperature, strongly oxidizing gases in the duct, both in the MHD system and in the exit gas steam generator, and with the alkali seed material added for ionization purposes. Since the seed material is expensive, it would appear necessary that it be almost fully recovered. Such a cycle is described in Mr. J. J. William Brown's paper, "Some Aspects of MHD Power Plant Economics"[1/].

The economic solution to these problems causes some pessimism as to the commercial attractiveness of open-cycle fossil-fueled MHD power plants in the near future. Consequently, closed-cycle systems, using so-called non-equilibrium ionization methods and those using liquid metal conductors, both of which permit somewhat lower temperature operation, are receiving increased attention.

One of the unusual aspects of MHD generation, offering mutual advantages to our two industries, is the possible recovery of nitrogen fertilizers and nitric acid. In the high-temperature gas flow conditions of the MHD generator, atmospheric nitrogen combines with oxygen to form nitric oxide. Fast quenching to low temperatures provides fixed nitrogen in the exhaust gas. Westinghouse Electric Corporation research engineers suggest that at current market prices this recovery process could prove to be economic.

The utility industry is supporting much experimental and developmental work in this country, and overseas as well. The Avco Corporation and a group of eleven electric power companies[2/] have been engaged in a joint research effort on MHD for several years. The Edison Electric Institute is supporting a liquid metal MHD development effort with Atomics International.

Figure 7 shows an MHD binary cycle using liquid potassium for the MHD portion. The resultant low temperatures give rise to optimism for an economic breakthrough in the MHD field. Experiments are under way on several schemes utilizing either a two-phase liquid metal system, or two different liquid metals with dissimilar properties.

There is greatly increased MHD activity in Great Britain and France, most of it supported by the large nationalized utility industries. One of the largest overseas projects is that of The Central Electricity Generating Board of Great Britain which has a $5.4 million program for an open-cycle prototype MHD plant at its Marchwood test laboratories near Southampton, England. The prototype, designed as a topper to a conventional thermal station, is to have a thermal input of 200 mw and an electrical output of 20 mw. It will burn kerosene enriched with oxygen[3/].

A major contribution towards the production of an MHD generator suitable for use as a topper in conventional power stations could be made by the new Electricité de France laboratory in Renardières, France. The MHD generator will have a continuous rating of 8 mw thermal at 3,000 K. The Renardieres' experiment will be on an open-cycle generator initially, but it is hoped to use an exhaust gas heat exchanger for preheating fuels at a later stage. This will be a fossil fuel-fired device using a mixture of 20 percent potassium (by weight) and methanol for seeding the combustion gases in the MHD generator[47].

One of the main differences between this and other devices is that "wall phenomena" ceases to be of major significance when the MHD duct volume is increased. When the volume to surface ratio is low, heat losses through the walls, the effect of friction, boundary layers, and turbulence all have a significant effect on performance.

With high fossil fuel costs in many areas overseas, and the low carrying charges associated with nationalized power system economics, the incentive for MHD development is much different than it is in this country where we have (1) comparatively low cost fossil fuel, (2) competitive nuclear power in medium to high cost fuel areas, and (3) largely an investor-owned industry where carrying charges on investment are substantially higher.

Results of research and development look encouraging and there is still much enthusiasm in the MHD field. Pessimistic views exist, mostly in the predicted timing of an economic breakthrough.

Fuel Cells

The fuel cell field is highly diverse and one perhaps of greatest interest to the chemical industry. This diversity takes many forms, and makes economic evaluations complex and nebulous. For instance, one method of classifying fuel cell technology is by operating temperature, as follows: the low range temperatures, up to 150 C, use dilute aqueous caustic and acids; the intermediate range -- temperatures 150 C to 400 C -- use concentrated acids and pasty caustics; the high range -- 400 C to 800 C -- use molten carbonates; and the extra high temperature range -- over 800 C -- use solid ceramic oxides as the electrolyte. It is evident that within this wide temperature range, widely differing materials of construction are required, and there will be a difference in performance results, both resulting in variations in cost of manufacture, operation and maintenance.

Hydrogen-oxygen cells are probably the most advanced as a result of development in connection with the aerospace program. Indicative of this are the three fuel cells exhibited by Allis-Chalmers Manufacturing Company last November at the Arkansas Inventors Congress and Space Symposium -- (1) a 3 kw fuel cell system for NASA's Apollo spacecraft; (2) a 750 watt hydrazine-oxygen system used to power a small submarine; and (3) a lightweight 45-watt hydrogen-oxygen system. General Electric reports success with the hydrogen-oxygen type using an ion-exchange membrane, and Pratt & Whitney have been successful in developing a modified Bacon cell of the hydrogen-oxygen type -- to mention only a few of the many projects under way.

The regenerative fuel cell is of particular interest to electric power companies because of the possibility of using off-peak power for regeneration. Hydrogen-oxygen systems, hydrazine-bromine, and potassium-mercury cells are all under development, but considerable research effort will be needed before these systems can be considered to be commercially usable for power generation. In fact, this appears to apply to all fuel cell systems at the present time.

The very large research and development effort in the aerospace program, costing many millions of dollars annually, is responsible for the high degree of technical success of fuel cells. In a broad sense, it appears that we now have or shortly will have fuel cells available in 25 watts to 10 kw range of power, lasting up to three months at 70 percent thermal efficiency. They have the ability to function regardless of the attitude or orbit of the space vehicle. They are relatively immune to the rigors of space environment and can produce potable water as a by-product. Cost per kilowatt of capacity is very high.

Present economic studies indicate that at best the net energy costs for a hydrocarbon fuel cell will only approach those for conventional central station operation. The fuel cell may serve as a dispersed power source on electric systems, particularly for special applications such as peaking service where cost of operation is not the determining factor for economic use. They may also have application as a mobile power source, such as for use with fork-lift trucks.

Further development for varied and special commercial applications will depend to some extent upon private industry's continued willingness to invest in the necessary research and development. Regardless of the amount industry is willing to invest, we must continue close surveillance on developments in the major industrial fuel cell programs. There are about 21 such projects that, even if partly successful, could affect the future of the chemical and electric power industries.

I believe we should continue to invest in research and development to insure results favorable to our industries, and to make (1) more penetrating-engineering-economic studies to obtain the facts and calculations as to the real economic potential, and (2) a conscious search for fuel cells and applications that can be turned to the benefit of the chemical and electric power industries.

DC to AC Conversion

In most cases, the advanced concepts of power generation have one common characteristic -- they produce direct-current power. The present attractiveness of extra high-voltage direct current for transmission has encouraged the equipment manufacturers to the extent that the advances in DC-AC conversion techniques may be ahead of the progress in energy conversion. It would appear that, when the advanced methods are ready for application, DC-AC conversion will not be a major technical or economic handicap in the use of direct conversion devices. Where DC can be used directly, such as in the electrochemical business, the problem does not exist even now.

Cryogenics and Fusion

In considering advanced methods of energy conversion, note probably should be taken of the results of physical research in the two extremes of the heat spectrum.

1. Cryogenics, involving the investigation of matter at temperatures near absolute zero, has advanced to the stage where complete design guides are published concerning the entire range of engineering and chemical requirements, including properties of various substances, production systems, materials behavior, insulation, storage, necessary related equipment, and safety procedures. This is of particular interest in the development of MHD and fusion devices requiring high strength magnetic fields. Commercial cryogenic magnets are now available in small sizes. Larger sizes will presumably be available when the demand requires.

2. A large amount of government and private research effort is being devoted to the fusion reactor. Economic power from the fusion reactor still appears far away, almost certainly not before 1980, and probably later. It appears possible that energy released during the fusion of light nuclei to form heavier or more stable nuclei may be removed directly as electric energy, but up to now a continuous net production of power has not been achieved. When it is achieved, it will probably stimulate numerous

forecasts as to the impact of fusion on the world's sources of electric power. It is not practical at this time to give other than preliminary thought as to what cycles might be used with the fusion process, and the economic aspect of the process is still further removed in time.

Summary

In closing, I will use three figures of a previous paper[5/] which attempts to predict for the next twenty years generator size, power generation efficiency and capital costs for four methods of advanced power generation. On these figures, the information has been updated to reflect the changes discussed herein, as well as the effect of anticipated improvements in today's conventional methods, such as the recent trend of decreasing cost of coal at our power plants, and the increased efficiencies of nuclear plants.

Figure 8 shows the predicted generator sizes for the next 15 to 20 years. There is doubt of achieving the predicted sizes of thermoelectric generators for the years 1975 and 1980 because of the materials problem and what is considered to be a lesser probability of large scale commercial application. No one is now seriously considering the possibility of building a 200 mw thermoelectric generator, as was predicted several years ago.

The delay in achieving thermionic generator sizes reflects, in part, an anticipated lesser research and development effort, and also perhaps the effect of increased efficiency of present nuclear cycles which may make such devices uneconomic.

The delays indicated in the MHD field could be wrong. The present pessimism for an economic breakthrough in the cycle using fossil fuel could cause this sort of a delay. However, early success in the liquid-metals cycles or other low temperature gas cycles could suddenly spur the effort, but as toppers and not as large individual units.

In the fuel cell field, the 10 kw goal may soon be achieved as indicated before, mostly because of the huge aerospace effort. Whether the predicted sizes indicated for 1975 and 1980 are attained will depend, in part, on the degree of support for the necessary research and development by investor-owned industries.

Figure 9 shows the future predicted efficiencies for these four advanced methods of power generation. The same reasons which apply for the delay in developing generator sizes also apply for the delays indicated in Fig. 10, which shows the predicted capital cost per kilowatt net for these advanced methods.

These predictions are based upon the successful outcome of research efforts. When they will be achieved, is a function of the magnitude of the research effort which will, in turn, be affected by improvements in conventional cycles. Encouraging progress has been made, and our scientists, engineers and chemists will, I am sure, solve the many and complex problems of our future energy demands. It will be to the mutual benefit of both the chemical and power industries to work more closely together to develop more efficient methods of power generation, and more effective use of our present equipment.

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Illinois Power Company
Indianapolis Power and Light Company
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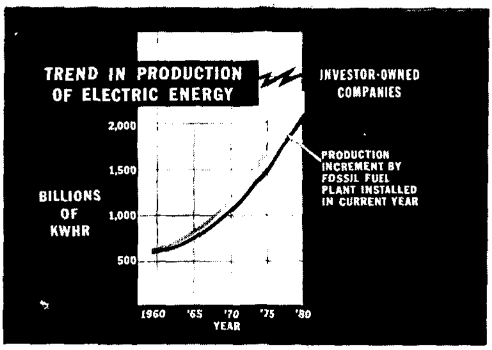

FIG. 1

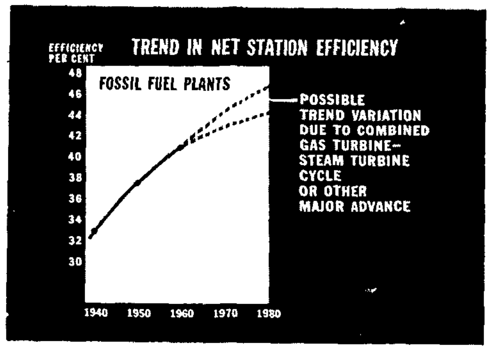

FIG. 2

COMPARISON OF PRESENT & PREDICTED ENERGY COSTS[a]

	PULVERIZED COAL		B.W.R.
IN-SERVICE DATE	1961	1968 *	1970 *
PLANT CAPACITY NET MW	327	515	550
CAPITAL COST $/KW	130	111	123
ENERGY COST MILLS / KWHR			
CAPITAL	2.09[b]	1.85[c]	2.02[d]
FUEL	2.47[e]	2.12[f]	1.63[g]
O & M	0.20	0.20	0.55[h]
TOTAL	4.76	4.17	4.20

(a) AT 80% CAPACITY FACTOR
(b) 11.3 % FIXED CHARGES
(c) 11.75 F.C.
(d) 11.5 % F.C.
(e) 28.0 ¢/10^6 BTU
(f) 24.0 ¢/10^6 BTU
(g) LEVELIZED PRESENT WORTH VALUE OF 20 YR FUEL COST
(h) INCLUDES SAFETY INSURANCE
* ESTIMATE

FIG. 3

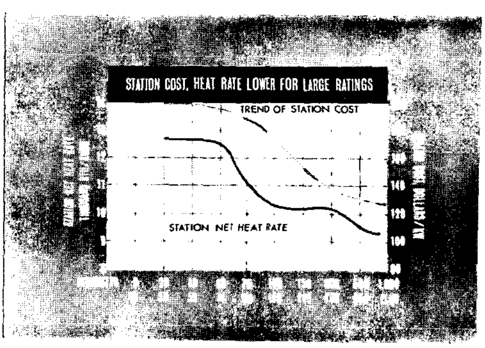

FIG. 4

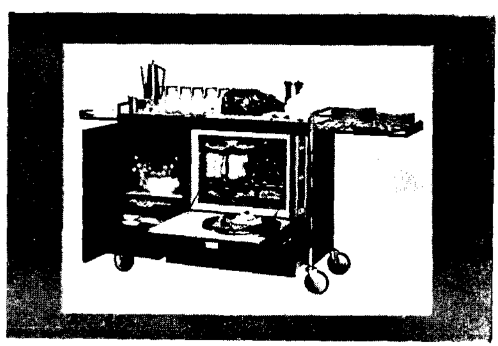

FIG. 5

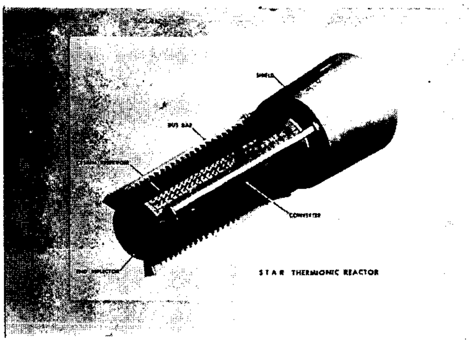

FIG. 6

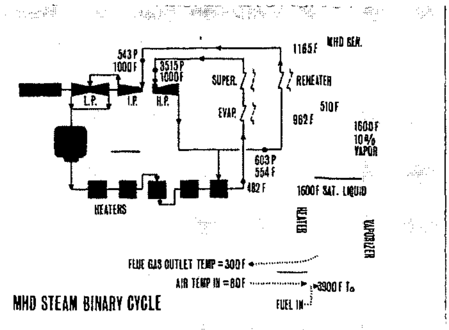

FIG. 7

	[illegible]	[illegible]	[illegible]	[illegible]
		[illegible]	[illegible]	[illegible]
			[illegible]	[illegible]

FIG. 8

PREDICTED POWER GENERATION EFFICIENCY – %

YEAR	THERMO-ELECTRIC	THERMIONIC	MHD	FUEL CELL
1970	5	10	- - -	50
1975	10	25	50	60
1980	10	30-40	55-60	60+

FIG. 9

PREDICTED CAPITAL COSTS–$/KW NET*

YEAR	THERMO-ELECTRIC	THERMIONIC	MHD	FUEL CELL
1970	1,000-2,000	- - -	- - -	200-300
1975	500-1,000	1,000+	200-350	100-200
1980	200-500	200	150-250	50-100

* THESE DO NOT INCLUDE COSTS OF CONVERTING DC TO AC

FIG. 10

CONVERSION OF FOSSIL FUELS TO UTILITY GAS

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Natural gas has nearly completely replaced the use of coal as a source of utility gas in the United States. As gas has shifted its status as a byproduct of petroleum, prices at the well in the Southwest, despite government regulation, have gone up sharply during the past fifteen years. Coal prices at the mine, however, have remained fairly constant during this period.

Natural gas is purchased by distribution companies from the transmission companies in the coal-producing area of West Virginia at about $0.37 per MMBtu (million Btu). Coal in the same area selling at the mine for $4.00-4.50/ton is equivalent in price to $0.16-0.18/MMBtu. As the differential between coal and gas prices increases, as is likely, the conversion of coal to gas at the mine becomes increasingly attractive.

It has been demonstrated in a small pilot plant at the Institute of Gas Technology that the organic content of oil shale hydrogenates to methane even more readily than does coal. There are vast reserves of oil shale in Colorado and Utah; thus, a large gas-making potential in the form of shale exists in that area. On the other hand, it is doubtful that Eastern shales are rich enough to produce gas economically in the foreseeable future.

The location of the rich Western shales is far from the large Eastern population centers. This means that gas from shale would have to be cheaper by about $0.20 to $0.30 per MCF (thousand cubic feet) than gas from coal to compensate for transmission costs to justify early development of these reserves for gas-making purposes. Markets on the West Coast are closer, but natural gas is appreciably cheaper there than in the East.

The rich shales of Colorado and Utah presently seem better suited for production of liquids by relatively simple retorting at atmospheric pressure to recover crude shale oil. By conventional hydrogenation processes, a high quality gasoline can be made from the oil at prices close to present gasoline prices. Thus, the development of processes to make gasoline from oil shale may occur before gas from shale is a reality.

A variety of processes for the conversion of distillate and residual oils to gas have been developed and are being used widely for baseload gas elsewhere in the world. In this country, oil is used to produce gas for peaking purposes on the East Coast only. Distillate fuels, which are relatively simple to gasify, cost $0.10/gallon, a raw material cost of about $0.70/MMBtu. Crude oil, and even residual oil, can be converted to gas by hydrogenation[7] or thermal cracking.[5] However, even at the low price of $ 2.00/bbl, about $0.33/MMBtu, the raw material cost would be approximately twice that of coal.

Therefore, although the same general coal and shale gasification and hydrogenation techniques that will be discussed in this paper can be applied to oil, and even though plant investment costs for gasification of oil would be lower than for coal or shale, the cost of oil is much too high at present for consideration of it as a feedstock for a baseload plant. Consequently, only those processes that are most promising for coal and oil shale will be considered in this paper.

UTILITY GAS FROM COAL

Coal Gasification

An excellent summary of past work on coal gasification and hydrogasification is given by C. G. von Fredersdorff and M. A. Elliott[9] in the recent supplementary volume of "Chemistry of Coal Utilization." No attempt will be made to review that field further in this paper.

A study of the economics of coal gasification indicates that it is preferable to gasify coal under pressure when a heating gas containing methane is desired. The only pressurized gasification process being used at the present time is the Lurgi. The Scottish Gas Board is currently using it in their plant at Westfield,[6] and it is also being used to make gas in Australia. The advantage of the Lurgi process is that due to the pressure of approximately 400 psig of the system, methane in appreciable quantities is obtained in the raw gas. Inasmuch as the methane-forming reaction is exothermic, it is possible to decrease the amount of oxygen fed into the gasifier. The Lurgi process requires a fixed bed, with coal being fed into the top of the gasifier through lock hoppers, and steam and oxygen into the bottom of the gasifier. Operation is nonslagging, requiring excess steam to maintain the temperature of the bottom of the gasification zone sufficiently low to avoid slagging of the ash.

The heating value of Lurgi gas after purification to remove carbon dioxide is in the range of 400 to 450 Btu/SCF. It is possible to make approximately 1000 Btu gas by employing catalytic methanation as an upgrading step to convert hydrogen and carbon monoxide to methane following Lurgi gasification. About 600 CF of oxygen is required to make 1000 CF of methane, including that methane which can be made by catalytic methanation of the hydrogen and carbon monoxide. In other gasification processes, where a suspension of coal is used with oxygen and steam at high temperatures, resulting in little or no methane in the product gas, about 1200 CF of oxygen is required per MCF of methane. Thus, the advantages of the Lurgi gas scheme for making a high-heating-value gas are obvious. A raw gas analysis from the Lurgi gasifier is:

CO_2	30.5%
H_2S	1.0%
C_nH_m	0.6%
CO	16.5%
H_2	42.0%
CH_4	8.6%
N_2	0.8%

Fig. 1 is a simple flowsheet of the major steps in the Lurgi gasification-catalytic scheme to produce gas having a heating value of approximately 1000 Btu/SCF. Using Eastern coals, it would be necessary to pretreat the coal to avoid agglomeration of the coal in the gasifier; conventional pretreatment consists of mild oxidation in the temperature range of approximately 600° to 900°F.

If it were necessary at the present time to convert coal to utility gas, we would have to select Lurgi gasification as the most advanced commercial process to accomplish this. However, there is under development a scheme using hydrogenation of coal that is economically more attractive.

Hydrogasification

Hydrogenation of coal to form methane proceeds very rapidly above temperatures of 1400°F and pressures of about 1000 psig. When methane is the chief product, rather than the liquids that are obtained when the temperature is lower, the process is called hydrogasification. Early work on hydrogasification was done by F. J. Dent and associates of the Gas Council in England, and has been continued recently in this country by the U. S. Bureau of Mines and the Institute of Gas Technology. The reaction of hydrogen with carbon to produce methane is highly exothermic. Rather than attempting to control the temperature within the hydrogasification reactor by means of cooling coils, a major improvement in the technology is injecting steam along with the hydrogen. The heat from the exothermic methane-forming reaction can be utilized by the endothermic steam-carbon reaction. Thus, additional hydrogen and carbon monoxide are made which can subsequently be reacted catalytically to form additional methane. The effect of steam addition is to decrease the hydrogen requirement to about 70 percent. In addition, the reactor construction is greatly simplified by avoiding internal heat exchange surfaces.

The hydrogasification process can be operated with either fluidized beds or moving beds with countercurrent contact. It is believed that pretreatment of the coal to avoid agglomeration can be avoided by dropping the fine coal particles into a devolatilization zone at the top of the gasifier. Thus, there would be no loss of methane that would accompany pretreatment procedures.

A simplified flowsheet of the hydrogasification process is shown in Fig. 2. About 50 percent of the carbon is gasified in the hydrogasification reactor. The remaining 50 percent is used in the gasifier with oxygen and steam to make hydrogen for the hydrogasification operation. The gasification step is done at a lower pressure, about 400 psig, followed by a CO shift, gas purification to remove CO_2, and then compression to 1000 psig. Steam of about equal volume is added to the hydrogen for hydrogasification.

The crude gas from hydrogasification is subjected to CO shift to adjust the hydrogen/carbon monoxide ratio to about 3/1 for methanation purposes, gas purification to remove carbon dioxide and sulfur compounds, and finally, catalytic methanation with suitable iron or nickel catalysts. It is possible to reduce oxygen consumption to about 320 SCF/MCF of total methane made in this process.

Hydrogasification and the Steam-Iron Process

Inasmuch as the cost of the product gas is greatly affected by the oxygen cost, considerable thought has been given to development of processes that avoid the use of commercially pure oxygen. One such process would be the combination of hydrogasification with a modernized version of the steam-iron process to make hydrogen for the hydrogasification step. This system is being investigated by a group of three companies: the Consolidated Natural Gas System, Texas Eastern Transmission Corporation, and Consolidation Coal Company in a pilot plant of the Institute of Gas Technology. Preliminary work on the steam-iron process was done by the U. S. Bureau of Mines[3] in their Bruceton Laboratories at 300 psig. The pressure in the Institute of Gas Technology pilot plant has been extended to 1000 psig with greater throughputs.

Hydrogasification would be carried out in the manner previously described with the exception that a stream of hydrogen and steam obtained from the steam-iron process is passed directly into the hydrogasification reactor. This scheme is shown in Fig. 3. Residual char from the hydrogasification step is sent without pressure reduction to a gas producer in which it is reacted with steam and air, rather than oxygen, to make producer gas. The producer gas reduces iron oxide, which is then reoxidized with steam in a separate vessel.

Because the steam and hydrogen can be made available at elevated pressures and temperatures, a considerable reduction of equipment is possible. Shifting of the carbon monoxide, scrubbing of the hydrogen stream to eliminate carbon dioxide, and subsequent compression are unnecessary. Injection and preheating of the steam for hydrogasification is avoided. The main advantage, however, is in the elimination of commercially pure oxygen. The spent producer gas still contains appreciable energy and can be expanded through a turbine to compress the air required for the gas producer. In addition, the spent producer gas may be burned to provide the steam which is required in the plant.

Gas Costs

Raw material costs and plant investment for gas made by these three schemes are summarized in Table 1. While data from pilot plants are by no means complete at this time, it is possible to make reasonable assumptions and to estimate the final gas costs. The plant size was taken as 90×10^9 Btu/day. Coal used in these estimates had a heating value of 12,500 Btu/lb. The pipeline gas composition was assumed to be the same in all cases, and had a heating value of 987 Btu/CF. By using a combination of iron and nickel methanation catalysts, it should be possible to produce a product gas that contains sufficient ethane and propane to yield a heating value close to 1000 Btu. It is possible to keep carbon monoxide below 0.1 percent. Plant costs, thermal efficiencies, and final gas costs are given. By use of the steam-hydrogen process as a source of hydrogen, plant costs for the hydrogasification plant can be reduced to about \$40 million from the \$65 million when hydrogen is made by oxygen-char gasification, and \$90 million for the Lurgi installation.

Fig. 4 shows graphically the gas costs under the three schemes, and the effects of coal and oxygen upon them. Final costs are complete and include con-

Table 1.-SUMMARY OF RAW MATERIAL REQUIREMENTS, PLANT INVESTMENT, AND GAS PRICE
90×10^9 Btu/Day Utility Gas From Coal

Coal Cost: \$4.50/ton
Oxygen Cost: \$7.00/ton (\$0.30 MCF)

	Lurgi Gasification, Catalytic Methanation	Hydrogasification, H_2 From Char, O_2, Steam	Hydrogasification, H_2 From Steam-Iron
Coal consumption, tons/day	6,540	5,220	4,600
Oxygen consumption, tons/day	2,300	1,200	none
Utility gas analysis, %			
CH_4		91.0	
C_2H_6		3.0	
C_3H_8		0.4	
H_2		3.0	
CO		0.1	
CO_2		0.5	
N_2		2.0	
Heating value, Btu/SCF		987	
Plant investment, \$Million	90	65	40
Plant thermal efficiency, %	55	69	78
Price of gas, \$/MMBtu	0.95	0.70	0.52

ventional utility return on investment, and federal taxes, in accordance with the procedure recommended by the American Gas Association and summarized later in this paper. Plant life was taken at 20 years, and gas cost is averaged for the 20-year period. No credit was taken for byproducts. These estimates indicate that with a reasonable degree of success in improving coal gasification technology, it would be possible to decrease the cost of utility gas made from coal from $0.95/MCF to $0.52/MCF for a 90×10^9 Btu/day plant.

UTILITY GAS FROM OIL SHALE

Comparison of Hydrogenation of Oil Shale and Shale Oil

Utility gas can be produced from oil shale by two routes: one is to hydrogenate the shale directly, and the other is to retort the material first and then hydrogenate the shale oil. Figs. 5 and 6 show process schemes for these two routes. In both processes sufficient shale is retorted to provide oil for making hydrogen and for boiler fuel requirements.

The same method for hydrogen manufacture is used. Synthesis gas is made by partial oxidation of shale oil, using 99 percent purity oxygen plus steam.[4,8] Raw synthesis gas is scrubbed free of carbon and hydrogen sulfide prior to carbon monoxide shift, in which the carbon monoxide concentration is reduced from 46 to 1.3 percent. Following the shift reaction, the carbon dioxide is reduced to two percent of the process hydrogen stream by scrubbing with hot carbonate solution. Process hydrogen is compressed to hydrogasifier pressure, 1000 psig.

Hydrogasification of oil shale is carried out in a moving bed, with solids and gas downflow at 1000 psig, and at a temperature range of 1050° to 1350°F. Although most of the methane is produced in this step, the hydrogasifier effluent contains substantial amounts of carbon monoxide. This is catalytically shifted to adjust the H_2/CO ratio to a value suitable for methanation. Prior to the latter step, sulfur compounds, benzene, and ammonia are scrubbed from the gas.

The alternate to direct hydrogenation of shale is the hydrogasification of shale oil produced by retorting the shale. Work at IGT on high-pressure hydrogasification of petroleum oils[7] showed that control of coke deposition from crude and residual oils would be necessary to permit continuous operation of a process not using some means of coke removal. A two-step process was developed. In the first step, the oil is catalytically hydrogenated at 3000 psig and 780°-790°F. Design of this step is based on work of the U. S. Bureau of Mines.[1,2]

The hydrogasification step is based on work at IGT. Because of the small production of carbon oxides in the hydrogasification step, only final purification is necessary following hydrogasification of the oil.

An initial comparison of the economics of the two processes on the same cost basis showed no significant difference, with prices of 68 and 69 cents/MMBtu utility gas for oil shale and shale oil hydrogenation, respectively. Both processes were designed for hydrogen/shale or shale oil ratios of 100 percent of the stoichiometric. The oil shale hydrogenation design included a hydrogen-methane separation step.

Experimental work on hydrogasification of oil shale subsequent to this design indicated that successful operation could be carried out at hydrogen/shale ratios much less than stoichiometric. Utility gas plant designs based on these ratios showed investment savings from both the elimination of hydrogen-methane separation and the reduction of the size of hydrogen plants. Reduction of the hydrogen/shale ratio results in increased carbon formation, but this is discharged with the spent shale residue and causes no operating problem, such as the plugging of reactor tubes, that could occur in shale oil hydrogenation at drastically reduced hydrogen/oil ratios. Since the direct hydrogenation of oil shale appeared to offer greater possibilities for utility gas cost reduction than shale oil hydrogenation, further economic studies were restricted to the former.

Reaction of Oil Shale with Synthesis Gas

One of the problems in hydrogasification of oil shale is the necessity of preheating the shale to about 1050°F to initiate the reaction. A solids downflow countercurrent solids-gas flow reactor is very advantageous for heat transfer, allowing the hot effluent gases to preheat the fresh shale at the reactor top, and the hot spent shale to preheat hydrogen at the bottom. However, since the shale must be preheated to 1050°F, while vaporization of hydrocarbons begins at around 700°F, a countercurrent flow will result in shale oil being carried out with the product gas. Recovery of this oil on spent shale, followed by hydrogenation in a second reactor, might be done, but that would complicate and increase the cost of the hydrogenation system. A solids-downflow cocurrent system prevents oil carry-over, but increases the heat transfer problem.

Experimental work in the pilot plant was carried out with cocurrent gas-solids downflow. Adapting such a system to a commercial installation would require that either the hydrogen stream be preheated sufficiently to bring the shale up to reaction temperature, or that a fluidized preheat section with internal heating tubes be installed in a section of the reactor. Bringing in sufficient heat with the hydrogen stream at the maximum temperature consistent with practical design requires a high hydrogen/shale ratio, which has been shown to be less desirable economically.

The use of raw synthesis gas from the oil partial oxidation reactors in place of hydrogen as the hydrogenating gas provides a way of preheating the shale as well as offering economic and process advantages. The heat-carrying capacity of the gas is increased by the carbon oxides and steam which accompany the hydrogen required for reaction. Computations show that a shale synthesis gas mixture temperature of 1050°F can be obtained with 2500°F synthesis gas from partial oxidation reactors if the shale is preheated to 500°F.

The use of raw synthesis gas directly in the hydrogasification reactors has economic advantages in addition to the above operating and cost advantages. The raw synthesis gas at 2500°F flows directly from the partial oxidation reactors to the hydrogasifiers. To avoid compression of the hot synthesis gas, it would be necessary to operate the synthesis gas generators at hydrogasifier pressure, 1000 psig. This raises reactor costs; however, synthesis gas cooling and scrubbing equipment, water-gas shift unit, contact tower and coolers, and hot carbonate scrubbing system, would all be eliminated from the hydrogen section in this scheme (Fig. 7).

At low equivalent hydrogen/shale ratios, with synthesis gas the heat-carrying capacity can be maintained by increasing the steam/oil ratio in the partial oxidation reactors, which increases the amount of hot gas for a given quantity of shale oil and oxygen.

Optimization of Hydrogen/Shale Ratio

A study of the economic effect of reducing the synthesis gas/shale ratio was made for equivalent hydrogen/shale ratios ranging from 61 to 0 percent of stoichiometric. Without external hydrogen, all hydrogen must be obtained from the oil shale, resulting in a low efficiency of carbon conversion. Shale preheat can be achieved either directly by a flue gas produced by combustion with oxygen, in the presence of steam, of enough oil to produce the required amount of flue gas, or indirectly by burning oil in air, and passing the hot combustion gas through heating tubes immersed in a fluid-bed shale preheat section. The latter appears to be a cheaper method because of the elimination of the oxygen plant and synthesis gas generators, which more than compensates the added expense of indirect preheat.

In order to show the economic advantage of using synthesis gas instead of process hydrogen as a source of external hydrogen supply to the hydrogasifier, estimates of utility gas costs when using the latter were also made. These estimates covered the same hydrogen/shale ratio as in the synthesis gas cases, and are based on cost data derived from the latter.

Comparison of Costs

The effect of hydrogen/shale ratio on utility gas price for the two sets of estimates is shown in Fig. 8. The 20-year average price of gas represents capital and operating charges typical of utility financing for a 20-year plant life. Both sets of costs pass through a minimum at about one-third the stoichiometric hydrogen/shale ratio. Total plant investment and shale requirements also pass through a minimum at this point. The existence of a minimum results from the fact that as less external hydrogen is used, incremental decreases in hydrogen/shale ratio result in more than proportional increases in shale required for hydrogasification and all the attendant costs of increased solids usage. At some point they overbalance the savings in hydrogen supply facilities. At the minimum price for each method, the use of synthesis gas has a cost advantage of 3 cents/MMBtu utility gas.

Operation without external hydrogen is undesirable because of the low percentage of conversion of oil shale to gas.

Table 2 summarizes major process items for plant designs based on optimum hydrogen/shale ratios with hydrogen and with synthesis gas. Breakdown of

Table 2.-SUMMARY OF RAW MATERIAL REQUIREMENTS, PLANT INVESTMENT, AND GAS PRICE
90×10^9 Btu/Day Utility Gas From Oil Shale

Oil Shale Cost: $0.72/ton
Oxygen Cost: $7.00/ton ($0.30/MCF)

	Reaction With Hot Synthesis Gas 32.5% Stoich H_2/Shale	Reaction With Process Hydrogen 36% Stoich H_2/Shale
Oil shale (40 gal/ton) consumption, tons/day	22,312	24,866
Oxygen consumption, tons/day	1,165	798
Utility gas analysis, %		
CH_4	79.5	86.4
C_2H_6	5.9	3.3
H_2	10.0	4.3
CO	0.1	0.1
CO_2	0.8	0.9
N_2	3.7	5.0
Heating value, Btu/SCF	942	947
Plant investment, $Million	57.1	60.2
Plant thermal efficiency, %	65	59
Price of gas, $/MMBtu	0.56	0.59

plant shale requirements in tons/day for the two designs is:

	Synthesis Gas	Hydrogen
Hydrogasification	12,780	13,852
Synthesis Gas or Hydrogen	6,156	5,436
Retorting for Fuel	3,376	5,578

When process hydrogen is used to hydrogenate oil shale, more shale is required in the hydrogasifier and less is retorted for shale oil than when synthesis gas is used for hydrogenation. With synthesis gas less hydrogen is made by CO shift, making it necessary to gasify more oil. When the synthesis gas is cooled from 2800° to 1050°F during mixing with shale, only about 14 percent of the carbon monoxide is shifted by reaction with the water present. When hydrogen is produced as a separate stream, 96 percent of the carbon monoxide is catalytically shifted at a lower temperature and with a high steam/carbon monoxide ratio. With synthesis gas, more of the methane is produced by methanation of CO in the hydrogasifier effluent than when process hydrogen is used (20 percent over 13 percent). This requires less shale to be handled in the hydrogasifier system.

Elements of Utility Gas Price

Fig. 9 shows graphically the proportions of utility gas price represented by oil shale and oxygen, as raw materials, as separate items from the total of capital and operating costs for the rest of the plant. For the studies on which these cost estimates are based, a mined shale price of $0.72/ton was used. At this price it represents about one-third of the utility gas price. Oxygen at $7/ton (including excess capacity) is one-sixth and one-tenth of the gas price for the synthesis gas and hydrogen processes, respectively. These two elements represent about one-half the gas price.

Shale Mining Costs and Shale Richness

The mined shale price of $0.72/ton was based on information supplied by Cameron and Jones, Inc., for a daily mining capacity of 25,000 tons. In order to allow for the possibility of variations in the cost of mined shale on gas price, Fig. 10 shows gas prices as a function of mined shale cost.

The cost estimates presented in this paper are based on 40 gal/ton Colorado oil shale. This is probably a higher quality raw material than would be available to plants manufacturing utility gas from oil shale, except through selective mining of wide areas.

The use of leaner shale increases the burden of unreactive rock that has to be mined, ground and sized, and processed in an oil shale conversion plant. Estimation of the effect of this on utility gas price is:

Shale quality, gal/ton	Utility gas price, $/MMBtu
40	0.556
30	0.658
25	0.746

In summary, utility gas can be manufactured by the hydrogasification of oil shale at reasonable cost. The most important process variable influencing the cost of utility gas is the hydrogen/shale ratio, with the optimum value being about one-third the stoichiometric value. From both an operating and economic standpoint, the best way to supply hydrogen is by synthesis gas. Oil shale price and quantity exert a greater effect on gas costs than any of the individual process steps. The major problem in making utility gas from oil shale, in contrast to coal, is in solids handling. As oil shale richness decreases, the solids-handling problem becomes more important and might make oil hydrogasification more attractive if it could be carried out at low hydrogen/oil ratios. This might be accomplished in a fluidized or moving coke bed as a means of removing carbon.

Correlation of Utility Gas Price, Investment, and Fossil Fuel Cost

The utility gas prices presented in this paper are 20-year average prices computed by an accounting procedure developed by the General Accounting Committee of the American Gas Association. This procedure is based on the financing of utility gas plants at 65 percent debt and 35 percent equity. Straight-line depreciation is assumed over a 20-year period and interest at 5 percent on the outstanding debt is charged. Seven percent return on undepreciated fixed investment is assumed. The 20-year effective average capital charge composed of federal income tax, debt, and net income amounts to about 5.8 percent. State and local taxes and insurance are taken at 3 percent and annual depreciation at 5 percent. This procedure has been programed for computer operation.

Fig. 11 presents a generalized correlation of utility gas price versus total capital investment for a 90×10^9 Btu/day plant at various levels of fossil fuel cost. The latter parameter is the cost of the fossil fuel (coal, shale, or oil) in $/MMBtu as fed to the plant, divided by the overall plant thermal efficiency of conversion to utility gas.

From a number of cost estimates of plants for making utility gas from coal and oil shale, relations between operating labor and daily material charges other than fossil fuel as percentages of equipment investment were derived for purposes of correlation. Operating labor and daily materials were taken as 2 and 0.5 percent, respectively, of total equipment, or bare cost. No byproduct credit is included. Capital investment is the bare cost plus contractor's overhead and profit, interest on fixed investment, and working capital.

Effect of Plant Size

Size of plant can have an appreciable effect on gas costs. A plant of only 90×10^9 Btu/day is not large enough to achieve the best economy. This is equivalent in product processed on a Btu basis to a petroleum refinery of only about 15,000 bbl/day capacity. The cost per unit of product is reduced by the petroleum industry by increasing the size of refineries to 50,000-100,000 bbl/day. It would be reasonable that coal gasification plants located at the mine would operate more economically if the size were increased to $300\text{-}400 \times 10^9$ Btu/day. Large pipelines readily transport $500\text{-}600 \times 10^9$ Btu/day.

Fig. 12 was prepared to show the effect of larger plants on the product gas cost. The effect of increasing the plant size on the unit cost, exclusive of fuel cost, was based on plant investment as a function of the 0.8 power of plant capacity. The raw material cost, coal or shale, was $0.23/MMBtu. All other costs were then assumed to vary as the 0.8 power of plant size. This is a simplication, but serves to illustrate the savings possible with larger plants. Gas that costs $0.60/MMBtu with a 90×10^9 Btu/day plant would cost about $0.50 with a 400×10^9 Btu/day plant (Curve A), and $0.50 gas from the smaller plant would cost $0.43/MMBtu with the larger plant (Curve B). Gas made from hydrogasification with hydrogen from the steam-iron process could be reduced from $0.52 to about $0.445/MMBtu.

It is interesting to note that with the foregoing assumption of the 0.8 power, the investment cost of a coal-to-gas plant would be less than that of a 30-inch pipeline, 1,000 miles long, for equal daily capacities. This length of pipeline would be required to bring gas from Louisiana as far eastward as the coal fields of West Virginia.

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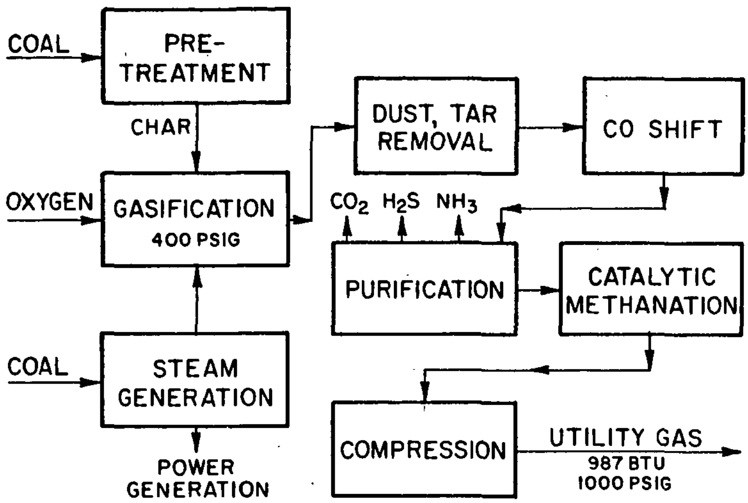

Fig. 1.-UTILITY GAS BY LURGI GASIFICATION FOLLOWED BY METHANATION

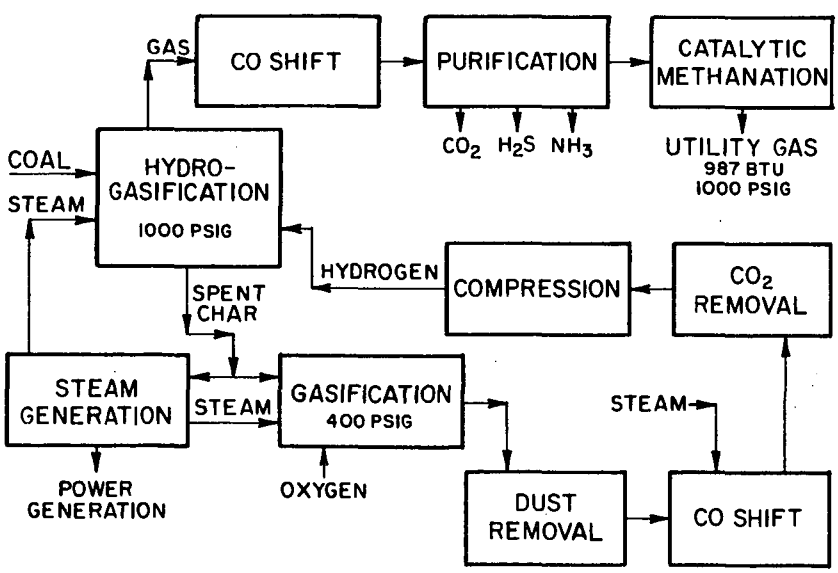

Fig. 2.-UTILITY GAS BY HYDROGASIFICATION, WITH H_2 FROM GASIFICATION OF CHAR, O_2, AND STEAM

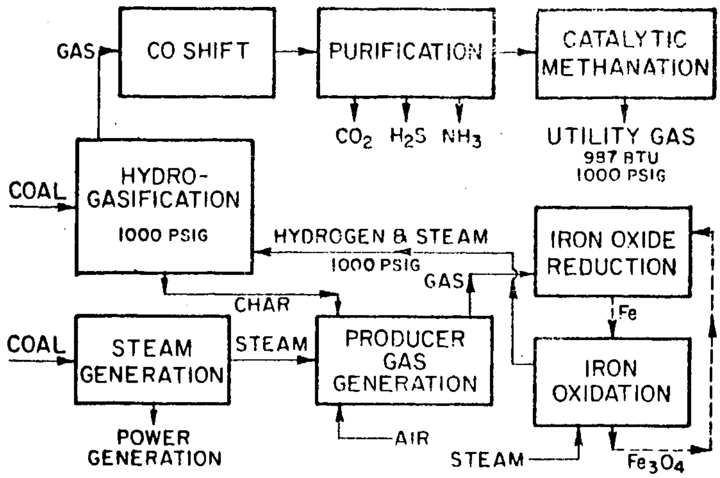

Fig. 3.-UTILITY GAS BY HYDROGASIFICATION, WITH H_2 FROM THE STEAM-IRON PROCESS

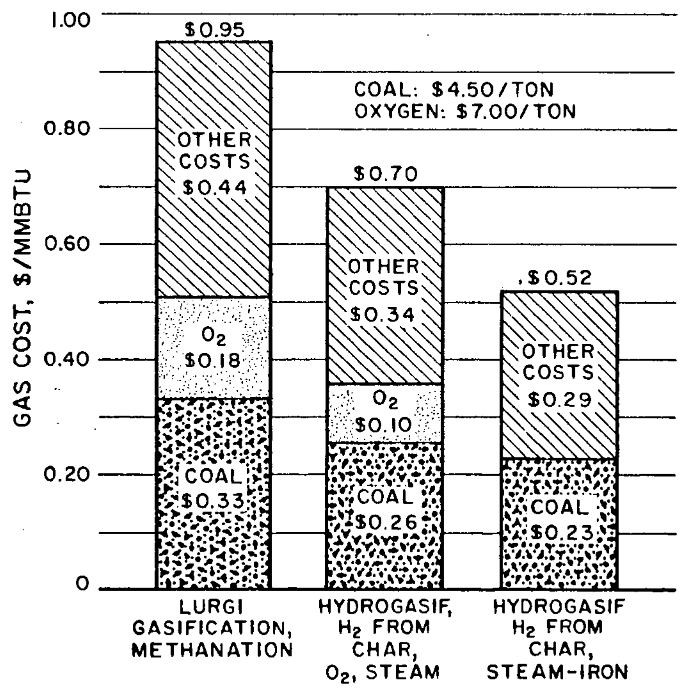

Fig. 4.-ELEMENTS OF UTILITY GAS COST IN GASIFICATION OF COAL (90×10^9 Btu/day)

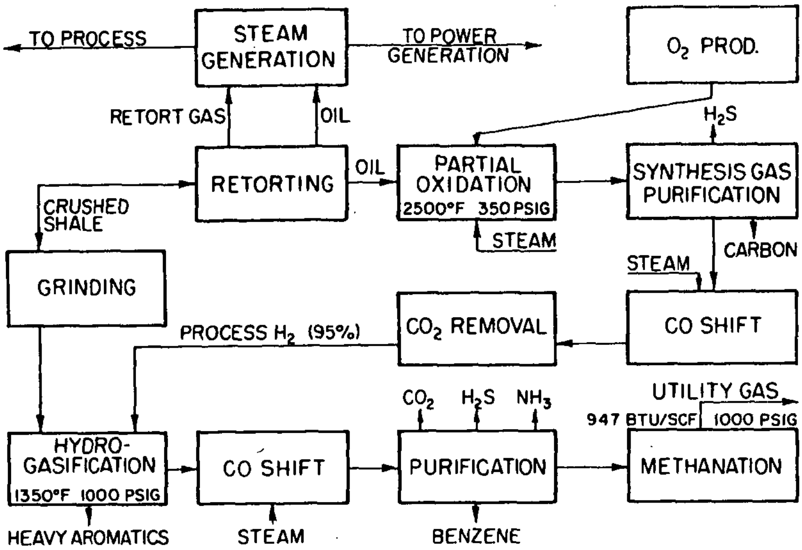

Fig. 5.-UTILITY GAS BY HYDROGASIFICATION OF OIL SHALE, REACTION WITH HYDROGEN

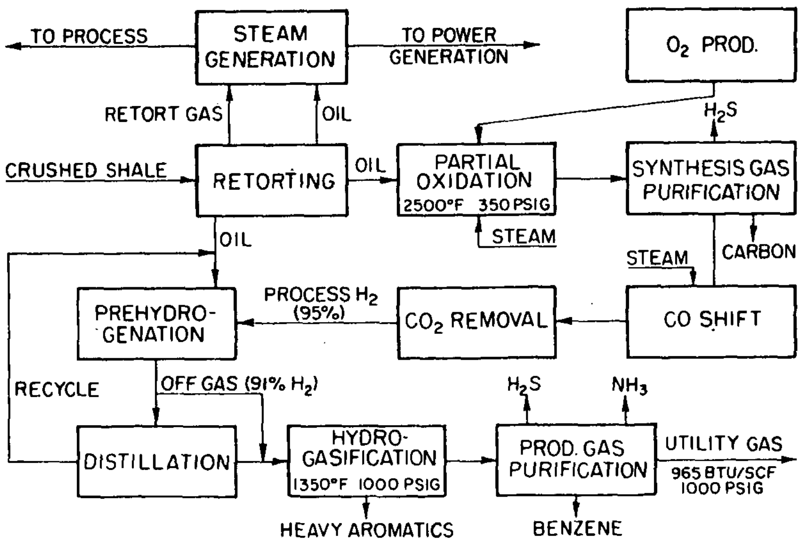

Fig. 6.-UTILITY GAS BY HYDROGASIFICATION OF SHALE OIL

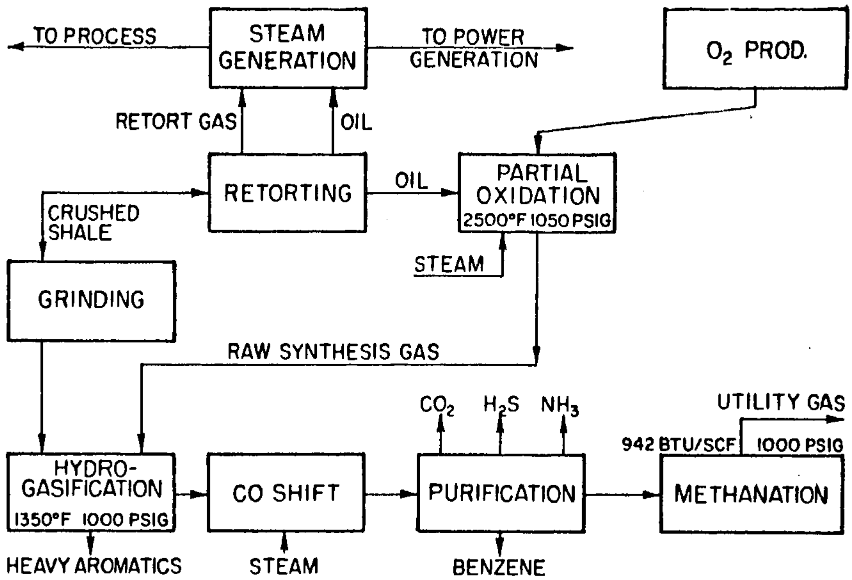

Fig. 7.-UTILITY GAS BY HYDROGASIFICATION OF OIL SHALE, REACTION WITH RAW SYNTHESIS GAS

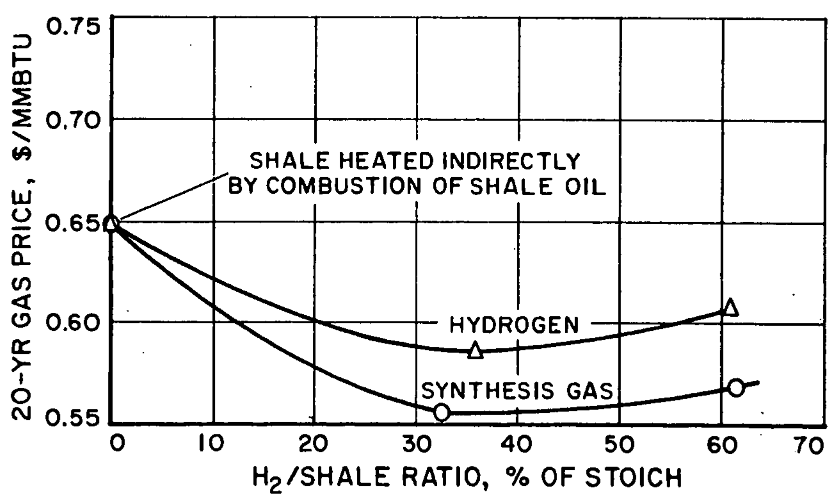

Fig. 8.-OPTIMIZATION OF HYDROGEN/SHALE RATIO, HYDROGASIFICATION WITH SYNTHESIS GAS AND PROCESS HYDROGEN

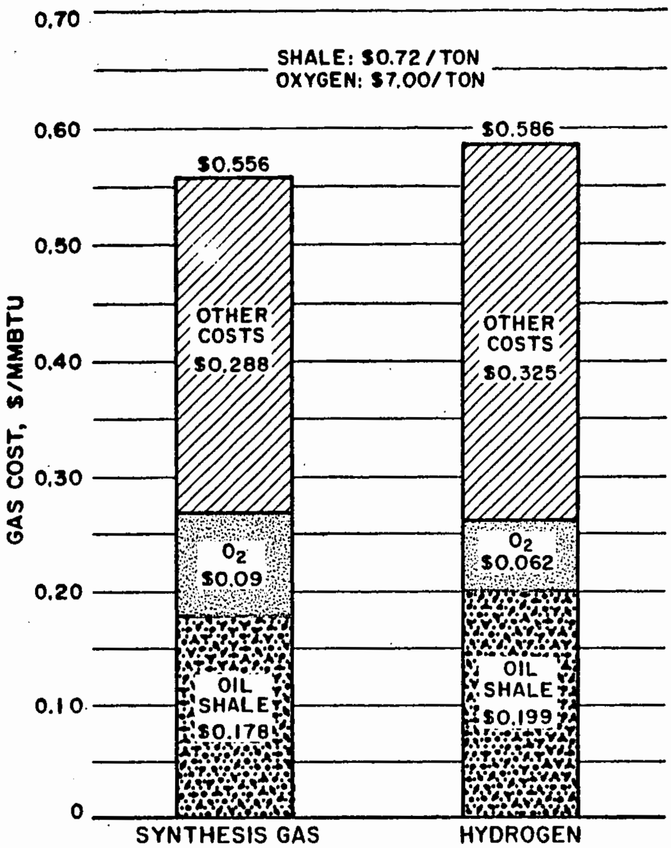

Fig. 9.-ELEMENTS OF PIPELINE GAS COSTS, HYDROGASIFICATION OF OIL SHALE BY REACTION WITH PROCESS HYDROGEN AND SYNTHESIS GAS AT ECONOMIC OPTIMUM H_2/SHALE RATIOS

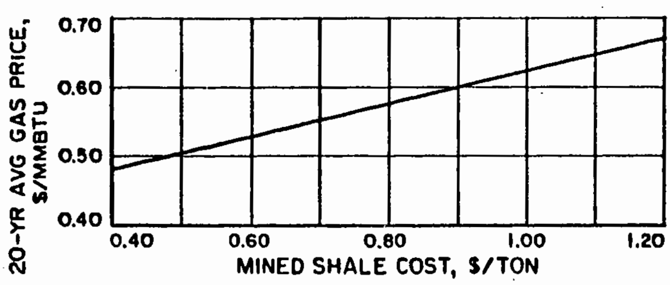

Fig. 10.-EFFECT OF MINED SHALE COST ON THE PRICE OF UTILITY GAS

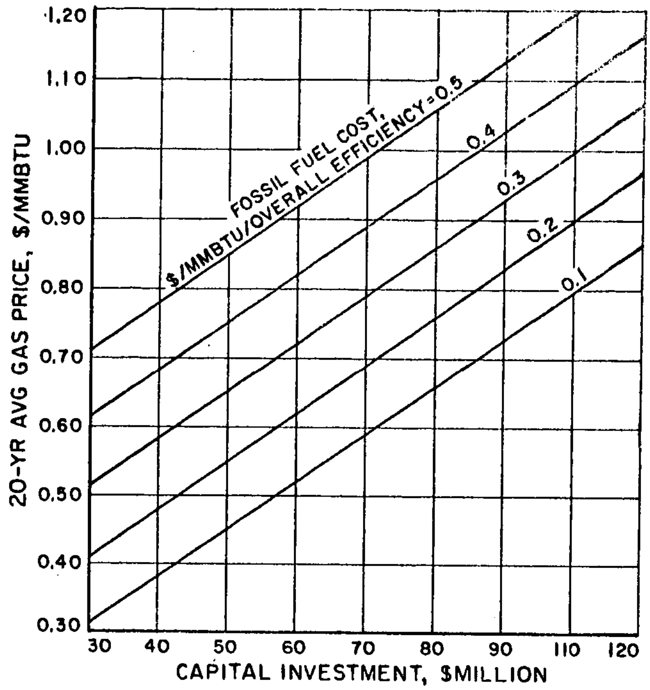

Fig. 11.-CORRELATION OF UTILITY GAS PRICE WITH INVESTMENT AND FOSSIL FUEL ENERGY COST (90×10^9 Btu/Day Plant)

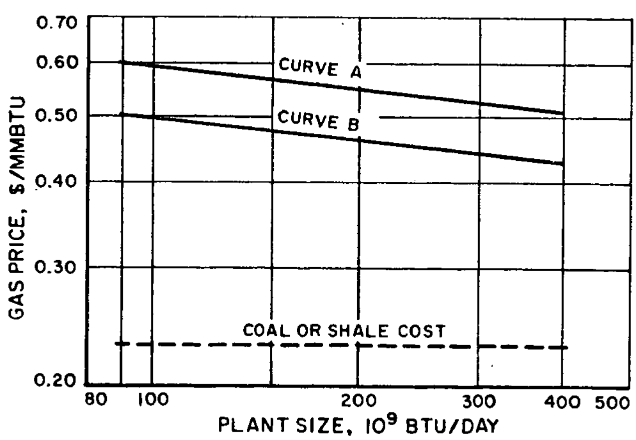

Fig. 12.-EFFECT OF PLANT SIZE ON PRICE OF PIPELINE GAS FROM COAL

CONVERSION OF FOSSIL FUELS TO LIQUID FUELS

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INTRODUCTION

Petroleum and natural gas production in the United States is under continuous study by organizations, both private and public, concerned with our energy supply. Over the years these studies have led to many predictions as to when synthetic liquid fuels would be needed. In the 1940's the United States became a net importer of petroleum, the excess of demand over supply coming from abroad. In 1941, for example, 1.402 billion barrels were produced and 1.486 billion barrels were consumed. Although there is no need to produce liquid fuels synthetically at the present time, it is comforting to have the know-how, just in case. Coal and oil shale are the logical raw materials since our mineable reserves are equivalent to trillions of barrels of oil, much of it near areas of consumption.

During the war years there was grave concern about our petroleum reserves, and a review of the facts at congressional hearings led to the Synthetic Fuels Act of 1944. From the research program supported by this legislation came significant developments in the processing of oil shale and the hydrogenation of coal and carbon monoxide. The laboratories at Rifle, Colo., and Laramie, Wyo., demonstrated improved mining methods and techniques for the conversion of oil shale to hydrocarbon products. At Bruceton, Pa., and Morgantown, W. Va., large research programs were carried out to demonstrate the methods of hydrogenation. At Louisiana, Mo., the demonstration plant contained a semi-commercial unit for the hydrogenation of coal and the latest concept, at that time, for the hydrogenation of carbon monoxide. The coal hydrogenation unit could produce 200 barrels product a day, and over 1.5 million gallons of gasoline were produced of which 1 million gallons were fleet tested by the armed services. Once the demonstration units at Rifle and Louisiana were in operation, economic studies were started, early estimates indicated costs of 9 cents a gallon for gasoline from oil shale and 14.5 cents a gallon for gasoline from coal.[1/]

In the period between 1949 and 1953, the economics of synthetic liquid fuels was evaluated by the Bureau of Mines, the National Petroleum Council, Ebasco Services, Inc., and the Bechtel Corporation. These studies, although starting with the same basic technological concepts, produced results which varied considerably. Some of the accountable differences are found in the financial structure assumed for the plants, the return on investment anticipated, and the cost of the mine, startup expenses, byproducts, and royalties. However, there was one definitive conclusion--none of the processes could produce a fuel that could compete with petroleum.

The National Petroleum Council[2/] arrived at the following selling price for gasoline at the refinery:

Oil shale	14.7 cents a gallon
Gas synthesis	29.4 cents a gallon
Coal hydrogenation	36.3 cents a gallon

These costs assume 6 percent return on investment after taxes and limited credit for byproducts. Although gasoline from shale can be produced at a lower cost, the areas suitable for production are remote from major markets and transportation costs to the west coast would increase the delivered price.

Development of the processes for the formation of liquid fuels were continued under the Synthetic Liquid Fuels Act until 1955. Research was then continued as part of the Bureau's minerals research and development programs. The demonstration plants were discontinued in 1953.

Other processes that might be a source of liquid fuels were part of the research program. Particular attention was given to low temperature carbonization where the yields of oil and tar may be relatively high. However, like the synthesis processes, fuels made by carbonization are not economically competitive today.

The overall objectives were clear: For synthetic fuels to be competitive, major cost reductions were necessary; for conservation of resources, technology had to be improved; for national security, one or more processes should be on the verge of commercial development.

Coal Hydrogenation

Improvements in the direct hydrogenation of coal were geared to making the process less costly by looking for cheaper sources of hydrogen, improved catalysts, less severe operating conditions, and reaction schemes that would simplify the overall plant. Good catalysts were found that could be applied in very low concentrations, but impregnation of the dry coal was required. Emphasis had been placed on the use of dry coal to eliminate the costly steps in paste preparation and handling. Although conversion of the coal was high, the distillable oil product still required further processing to make it stable enough to be used as an automotive or aircraft fuel. Thus only negligible savings could be demonstrated. An attempt to eliminate some of the refining was made by hydrogenating coal in a high temperature, one-step process. The reaction rate could not be controlled at temperatures above 480° C unless the catalyst concentration was low, but then coking occurred.

Another approach was to provide longer reaction times at a much lower pressure and to use more catalyst. It was demonstrated that the conversion of hvcb coal at 2000 psig was about the same as that obtained at much higher pressures and that a distillable oil yield of the same magnitude could be recovered. Coal conversions, for example, were around 95 percent at 2000 psig, and the average yields of distillable oil were about 65 percent. A further consideration was the anticipated trend to gas turbines and heavier fuels that require less refining. It has been demonstrated that heavy fuel oils could be produced by hydrogenation as low as 1500 psig.3/ Economic gains could be realized from the reduced pressure operation requiring less gas compression and lighter construction. These advantages were partially offset by the increase in reactor volume required. Rough estimates indicated that the price of a gallon of distillate could be reduced from the NPC base figure of 36 cents per gallon to about 25 cents per gallon--a considerable saving but still far from competitive with gasoline from petroleum at 10 to 12 cents a gallon.

Gas Synthesis

The hydrogenation of carbon monoxide to liquid fuels is a gas phase catalytic process with several reaction systems possible. The first reaction systems were fixed beds with low throughput, but it was not long before improved reactors were developed. Among the later systems were the fluidized bed, oil circulation, slurry, and hot gas recycle. Fluidized bed reactors were not investigated by the Bureau of Mines for the synthesis reaction because private industry was developing them. The Bureau concentrated on the latter three processes to evaluate effectiveness, life, and selectivity of catalysts and economics of the systems. For one reason or another all were eliminated except the hot gas recycle process which has prevailed because of catalyst shape developments which reduced pressure drop to a negligible value and operating flexibility. Even at high recycle rates of 10 to 30 volumes of recycle gas per volume of fresh feed gas, the recompression costs remain relatively low. The improvements that made the difference were activated steel lathe turnings having about 95 percent of void space in a reactor, parallel plate assemblies with the catalyst flame sprayed on the surface, and the latest operable system which merely has the catalyst flame sprayed on the wall of the reactor. Heat transfer problems in the last configuration are limited to the rate at which the heat of reaction can be transferred through the pipe wall. Reactors of this advanced type are more versatile than previously mentioned designs because they may be used for liquid or gas production. The other systems capable of this bi-functionality are the fluidized bed and fixed bed reactors. The product composition can be altered by changing the catalyst composition or sometimes its pretreatment to make liquid or gaseous hydrocarbons or oxygenated compounds. Regardless of the reaction system, it still takes about 650 cubic feet of synthesis gas to make a gallon of liquid product and 4000 cubic feet of carbon monoxide and hydrogen to make 1000 cubic feet of methane. Using a synthesis gas cost of 15 cents per thousand cubic feet from coal at $4 a ton, the contribution of gas to the total cost is already 9.8 cents per gallon, or 60 cents per 1000 feet of high Btu gas.

Oil Shale

Shales that will yield oil on pyrolysis are widely distributed in the United States, but the deposit of most immediate interest as a possible source of liquid fuels is in Colorado. This deposit in the Green River Formation is the world's largest reserve of hydrocarbon material. The deposit in Colorado is the smallest in area, about 1,500 square miles, but represents the largest reserve, about 600 billion barrels of oil in beds that will yield an average of 25 gallons per ton.[4/] The Utah and Wyoming deposits have not been completely evaluated but represent roughly 120 billion and 40 billion barrels of oil, respectively. The oil produced differs from petroleum in some important respects, but it can be refined by suitable processes to yield liquid fuels and other products now obtained from petroleum.

Mining costs, computed during the period of operation in the 1940's, ranged between 47 and 56 cents per ton.[5/] They included underground labor, supplies, depreciation, taxes, and administrative overhead. It is difficult to translate these costs to the present because improvements in mining techniques and equipment, such as rotary drills and ammonium nitrate based explosives, tend to offset increased labor costs and capital investment. The mining method as developed is applicalbe to cliff-face locations in the Colorado River drainage area. Most of the huge reserve in the Piceance Creek basin of Colorado is in thicker beds away from the cliff face and will require the development of special techniques for recovery.

The Bureau and several cooperating organizations have conducted crushing tests on oil shale, using jaw, gyratory, impact, and roll-type equipment. Resulting data have proved useful for some design purposes but are probably inadequate for exact design of a commercial oil-shale crushing plant. The tough, elastic Green River oil shale tends to form slabs that present screening and handling problems.

More than 2,000 oil-shale retorting systems have been patented throughout the world, but these may be grouped into a few classes on the basis of method of heat transfer (Table 1).

TABLE 1.- Classification of retorts

I. Heat is transferred to the shale through a wall.
II. Heat is transferred to the shale from combustion of product gases and residual carbon within the retort.
III. Heat is transferred to the shale by passing previously heated gases or liquids through the shale.
IV. Heat is transferred to the shale by mixing it with hot solids.

No single process is best for use under all conditions. Research is being conducted by both Government and industry in an effort to develop the technology needed to produce fuels economically from Green River oil shale. Three processes have received most recent attention. Two of these, the gas-combustion process developed by the Bureau of Mines and the process of Union Oil Company of California, use combustion gases for heat, whereas the third one, a process developed by the Oil Shale Corporation (Tosco), retorts the shale by contact with heated ceramic or metal balls.

In the gas-combustion process an upward-flowing stream of gas contacts a descending bed of broken shale. Recycled product gas entering the bottom of the retort absorbs heat from the retorted shale. At an intermediate point, air is introduced to burn the gas and some residual carbon on spent shale. The hot gases heat the shale to produce oil that leaves the retort with the gases as a fine mist. Attractive features of this process are high thermal efficiency, oil yield, and retorting rate. Development of this process was discontinued in 1956 before it had been completely perfected but has recently been resumed as the result of leasing the Anvil Points Facilities of the Department of Interior to the Colorado School of Mines Research Foundation. Through a subsequent contract with the Foundation, Socony Mobil Oil Company and Humble Oil and Refining Company are conducting research to complete development of the process.

The Union Oil Company retort is a countercurrent, moving bed type in which a rock pump at the base of the retort forces the shale upward through the retort. Heat for retorting is produced by the combustion of the carbon on the spent shale using air drawn down through the retort. Oil vapors in the gas stream leaving the retorting zone are condensed on the cold shale in the lower part of the retort. This process has essentially the same advantages as the gas-combustion process.

The Tosco process utilizes a horizontal rotating kiln in which pulverized raw shale is heated by contact with preheated, closely sized metal or ceramic balls. Carbon residue on the spent shale is used as fuel for reheating the balls. This retort will presumably form the basis for commercial operations that have been announced by Colony Development Corporation, which is a joint venture of Standard Oil Company of Ohio, Cleveland Cliffs Iron Company, and the Oil Shale Corporation.

As an alternative to the preceding processes, retorting oil shale in place in the formation is a possibility. Because this approach involves a different set of costs from those for mining, crushing, and surface retorting, it may be a more economical way to produce shale oil. Further, it should be applicable to many deposits not readily amenable to the mining approach and would eliminate the necessity for disposing of spent shale. However, development of the process presents formidable research problems. For example, oil shale is essentially impermeable, so one of the first problems is to create and maintain suitable permeability. Fracturing by conventional petroleum techniques and by nuclear explosives is being investigated. One drawback is that oil shale expands when heated and may result in the closing of the required combustion path.

Oil produced from shale of the Green River Formation frequently has properties that require the application of degradation processes, such as visbreaking, before the oil can be transported conveniently by pipeline. Also, these properties present some problems in the application of standard petroleum refining processes. For example, the nitrogen content of 2 percent, which is particularly high by petroleum standards, reduces the efficiency of catalytic processing techniques, and its presence in products promotes instability. Hence, special refining techniques are required. Hydrogenation is an effective process[6] for removing nitrogen, sulfur, and oxygen from shale oil and for producing excellent yields of high quality jet, diesel, and distillate fuels. Such hydrogenated oils also are satisfactory charging stocks for catalytic cracking and reforming processes[7] and may be suitable for use in manufacturing lubricants. Because of the potentialities of hydrogenation, most of the Bureau's recent refining research has been devoted to this method.

Because shale oil differs in composition from most petroleums, converting it to some products may result in byproducts not commonly obtained from petroleum, at least not in as large quantities. Among these may be phenols, pyridines, and ammonia. Others that are also commonly obtained from petroleum are hydrogen sulfide, sulfur, and specific olefinic or aromatic hydrocarbons. In addition to the byproducts from shale-oil processing, others may result from the retorting process. Because the exact byproducts obtained in any commercial operation will depend on details of the process used, their impact on the process is difficult to predict.

Bituminous Sands and Other Hydrocarbons

Deposits of outcropping bitumen-impregnated rocks and near-surface deposits of heavy crude oils in the United States are attracting attention as sources of fuels. Interest in bituminous sand deposits of the United States stems from extensive studies of the world's largest deposit--the Athabasca tar sands in Canada--that culminated in a commercial 45,000-barrel-per-day plant now being constructed by Great Canadian Oil Sands, Ltd., in northeastern Alberta Province.

The scattered occurrences of bitumen-impregnated rocks in the United States, including Alaska, have not been evaluated in detail; potential reserves in place are roughly estimated to be about 10 billion barrels,[8] of which the largest deposits in Utah, Texas, and California represent about 2 to 3 billion barrels of bitumen in place. A survey of information available on these domestic occurrences has been made by Ball Associates, Ltd., under a contract with the Bureau of Mines. Results of the survey will be published.

The only commercial production of fuels from a nonconventional source utilizes gilsonite, a hydrocarbon occurring in limited quantity in the Uinta basin in Utah.[9] For several years, the American Gilsonite Company mined about 1,000 tons of gilsonite daily and transported the crushed solid material in a water slurry 72 miles by pipeline to its refinery. Efficient hydraulic methods developed for mining and transporting the gilsonite, including boring machines for drilling large-diameter (up to 62 inches) tunnels and shafts, offer advantages for recovering other minerals such as coal. At the refinery, the crushed gilsonite is melted, mixed with hot recycle oil, and refined into 1,700 barrels of gasoline and 300 tons of metallurgical grade coke per day.

For several years natural gas was considered as the raw material for the production of synthetic liquid fuels and waxes using the Fischer-Tropsch synthesis. In the 1940's natural gas had not yet become the preferred fuel for home heating and industrial firing, partly because an adequate pipeline system was not in existence. Large quantities of natural gas near the source of supply could be contracted for at about five cents per thousand cubic foot. Consumption was around 2 trillion cubic feet per year. Most of the major oil companies and engineering companies developed workable processes for converting natural gas to higher hydrocarbons and had worked out most of the analyses of their products. The only domestic synthetic liquid fuel plant to get off the ground was the one built at Brownsville, Tex., by Carthage Hydrocol in 1950. The Amoco Chemicals Corp. took over the plant in 1953 and after engineering modifications declared the process as being technically sound. However, by 1957 the consumption of natural gas had risen to 10 trillion cubic feet. Raw material and other costs made the process uneconomical, and the plant at Brownsville, Tex., was shut down in 1957.

Today the only large synthetic fuels plant known to be in operation is the SASOL plant near Johannesburg, South Africa. After several years the operation is reported to be in the black and expansion is continuing. Economic operation is possible only because the coal is inexpensive and transportation costs are high to bring petroleum products from the coast. Coal is delivered at the plant for less than $1 a ton. Gasoline sells for 25 cents per gallon at the refinery yielding a net profit of about 8 cents a gallon. About 40 percent of the revenue from the SASOL units come from the sale of byproducts used for the manufacture of synthetic rubber, plastics, waxes, and fertilizers.

The Office of Coal Research, established in 1961, includes liquid fuels as one of its objectives. An early contract was with the FMC Corp. to convert coal by multistage carbonization into a liquid material to carry the char and other particles in a pipeline. By 1964 small scale laboratory tests had been completed, and a 100 lb per hour plant was scheduled for operation.[10] One of the experimental objectives has been to convert as much as possible of the 41 percent of volatile matter in Elkol coal to liquid products. The highest tar yields reported have been less than half the estimated total.

The General Electric Co. had planned to use a high-voltage corona discharge as an agent in the hydrogenation of coal into a liquid, gas, or chemicals. Small scale experiments indicated that insufficient activation was produced by the corona discharge, and work on a larger scale has been suspended. An economic estimate presented last year[11] indicated that the break even point was at a product selling price of 2 cents per pound and a corona efficiency of 1.5 kwh/lb coal reacted.

Project gasoline was first evaluated by the Ralph M. Parsons Co. and was considered to be feasible. The process as proposed by the Consolidation Coal Co. consists principally of extraction of a large part of coal in a recycle solvent, filtration, separation of the extract from the recycle oil, and upgrading of the extract by catalytic hydrogenation. Estimates based on studies up to the present time indicate that a commercial plant could make gasoline at a cost of 13.6 cents a gallon.[12] Hydrogen is a costly item in the process, and another OCR contract with the MHD Research Corp. anticipates the production of hydrogen in a plasma for 25 cents per thousand cubic feet compared with 40 cents or more per thousand cubic feet by conventional methods.

The Atlantic Refining Co. has proposed a process to mix coal and residual fuel and to treat the mixture as a refinery feed stock. The coke residue would be burned in an electric-generating station. It is estimated that the combined feed to the coking unit would recover about 30 percent of the coal as liquid product, thereby reducing the amount of crude charged to the refinery by about 30 percent.

Conclusions

Supplies of crude petroleum and natural gas, although abundant, are not inexhaustible, and provision is being made for the time when our vast coal and oil shale reserves will be called upon to supply a significant quantity of liquid fuels. The Bureau's approach on coal research has been to continue theoretical and practical studies to reduce costs by improving stages in the process or by developing new processes. A flexible, integrated plant might emphasize production of different fuels or byproducts under different economic conditions and even at different times of the year. To reduce hydrogen requirements, an alternative is the partial conversion of coal whereby most of the hydrogen is utilized as a hydrocarbon product. The char product is used for generating power or making additional hydrogen by gasification.

In recent years, oil shale research by the Bureau of Mines has been limited to small scale laboratory studies on refining and analysis. Large scale research and commercial development have been resumed within the last year. The cost of producing gasoline from oil shale is almost competitive with gasoline from petroleum on the west coast. One of the main problems is the isolated location of major deposits.

The recent process developments discussed have added more to refined technology rather than provide significant savings in cost. As research is continued, more savings will probably be shown but not large ones unless they occur in the areas of gasification or reaction kinetics. It has been amply demonstrated both in the United States and elsewhere in the world, that liquid fuels can be made from coal. Except in isolated cases, costs are too high for coal to be a real contender with petroleum at current prices.

Only by continued research will the remaining problems be solved. Research on both the fundamental level and engineering level will be continued in the hope that a major breakthrough on the costly steps can be achieved.

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SOME ASPECTS OF THE TRANSPORTATION OF BITUMINOUS COAL 1/

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Since the war there have been significant changes in the transportation pattern of bituminous coal. An examination of these shifts will be the major burden of this report. However, for a better understanding of these changes in transportation, it will be useful first to review briefly the general marketing trends and the economic climate in which the postwar coal industry has developed.

The demand for coal is "derived" in the sense that its nature and extent is determined by the demand for the services and products which it helps to create - electricity, steel, such industrial products as chemicals, paper, etc. In other words, where the demand for electricity increases the need for coal and competitive fuels also expands. This relationship is well illustrated by economic developments in the postwar years.

At the end of the war, the pent-up demand for durable goods, particularly household items, appeared insatiable. Both in newly constructed homes and buildings and in those already functioning, the demand for appliances using some form of energy mushroomed. For instance, in 1947, 0.9 percent of our personal consumption expenditures were for electricity, with an additional 0.5 percent for gas. By 1962 these percentages had climbed to 1.5 and 1.0, respectively. An even more significant indicator of the sharp increase in energy consumption is to be found in the figure "average kilowatt-hours used per customer." The following tabulation shows the postwar growth in this statistic.

Average kilowatt-hour per customer	1946	1963	Percent Increase
Residential	1,329	4,442	234.2
Commercial	7,224	23,225	221.5
TOTAL	5,422	13,367	146.5

Increases in the use of other sources of energy have also been substantial.

Along with the sharp increases in the use of coal, oil, and gas, have been certain trends in the economy which though more remotely connected with energy consumption have had considerable impact. Some of the trends in the general economy have had and will continue to have a profound effect upon the coal industry and upon its ability to compete in the energy market. The scope of this paper and limitations of time and space prevent any elaboration. These postwar changes in our economic environment have been: (1) the trend toward the substitution of price competition for service competition; (2) an erosion in the price structure - discount pricing, etc; (3) the trend toward diversification of interests; and (4) the growth of mergers and consolidations. Each of these is having a profound, though not always direct, impact upon the coal industry and each has been instrumental in shaping the transportation pattern for coal. 1/

Before discussing transportation and transportation trends for coal, an understanding of market shifts since the war is essential. This back-drop is shown in Table 1 below which sets forth the profound changes which have materialized since 1946 in the uses of coal.

1/ The term "coal" as used here and throughout the paper refers to bituminous coal and does not include anthracite.

TABLE 1

BITUMINOUS COAL CONSUMPTION
By User Group, 1946-1963
(Thousands of Net Tons)

	1946	1950	1955	1960	1963	Percent 1963 of 1946
Electric Utilities	68,743	88,262	140,550	173,882	209,038	304.1
Coking Coal	83,288	103,445	107,377	81,015	77,633	93.2
General Industry	249,671	177,673	122,465	95,127	99,006	39.7
Domestic Industry	401,702	369,380	370,392	350,024	385,677	96.0
Retail Deliveries	98,684	84,422	53,020	30,405	23,548	23.9
Domestic Consumption	500,386	453,802	423,412	380,429	409,225	81.8
Canada	21,880	23,009	17,185	11,625	13,762	62.9
Overseas	19,329	2,459	34,092	24,870	33,316	172.4
Total Consumption	541,595	479,270	474,689	416,924	456,303	84.3

PERCENT OF TOTAL CONSUMPTION

	1946	1950	1955	1960	1963
Electric Utilities	12.7	18.4	29.6	41.7	45.8
Coking Coal	15.4	21.6	22.6	19.4	17.0
General Industry	46.1	37.1	25.8	22.8	21.7
Domestic Industry	74.2	77.1	78.0	83.9	84.5
Retail Deliveries	18.2	17.6	11.2	7.3	5.2
Domestic Consumption	92.4	94.7	89.2	91.2	89.7
Canada	4.0	4.8	3.6	2.8	3.0
Overseas	3.6	0.5	7.2	6.0	7.3
Total Consumption	100.0	100.0	100.0	100.0	100.0

In the post-war period heavy losses were experienced in the consumption of railroad fuel and in the retail market where gas and oil, particularly the former, caused heavy erosion in coal's markets.

The introduction of the diesel locomotive started the precipitous drop in railroad coal consumption. Decline in retail deliveries was over a longer period, but was very substantial. For purposes of later comparisons, railroad fuel has been included in "general industry." For our purposes, railroad coal consumption today is a negligible factor. The Bureau of Mines recognized this in dropping the separate "Railroads" category of consumption in 1961.

The full impact of the two market changes may be seen in the following:

	Millions of Net Tons		
	1946	1963	Tonnage
Electric Utilities	68.7	209.0	+ 140.3
Railroad Fuel	110.2	1.0(E)	- 109.2
Retail Deliveries	98.7	23.5	- 75.2
Net Change In These Categories			- 44.1

(E) = Estimated

Note that in 1963 the electric utilities consumed 209.0 million tons of coal. In 1946 the combined consumption of the railroads and retail outlets was 208.9 million tons.

Finally, a consideration which has had considerable influence in carving out traffic patterns, is the changing importance of markets. The unit train, for example, is particularly adapted to moving utility coal for a market which was in fourth place in 1946, being exceeded by general industry, railroad fuel (not shown) and retail deliveries, yet by 1963 was in first place.

The changes in coal's other markets were much less spectacular. None could match the rapid growth of utility demand which set the stage for large volume movements and the fall-off in retail which as a result used less volume in shipping.

Distribution statistics in useable detail were not available prior to 1957, at least statistics which could be compared to those of the 1957-1963 period. Statistics in the last seven years have permitted the analysis of coal distribution by method of transportation, by user category, and by districts of origin and states of destination.

Finally, we are using only coal-competitive areas in the transportation statistics which follow. Inclusion of states with heavy gas or oil consumption and using little or no coal would have little usefulness and could add complexity to this presentation.

The transportation patterns for coal in the United States range from the railroads which handle some three-fourths of all shipments, through water and motor carriers to the coal pipeline, which while presently inactive as will be discussed at a later point, still remains an important factor in any consideration of future distribution.

Distribution of coal by each of these media, except the coal pipeline, is included in the quarterly summaries of distribution which have been published by the Bureau of Mines starting with 1958. 1/ Because of its confinement to one producer and its relatively limited life, the pipeline does not lend itself to statistical trending and the establishment of firm relationships. Additionally, such information, even if available, could not be made public without disclosure.

We will briefly discuss the coal pipeline after reviewing the 1957-1963 period with respect to the more conventional forms of coal transportation.

Tables 2A and 2B show the changing pattern of coal transportation in the seven-year period, 1957-1963. These figures do not show distribution by mode of transportation, an approach reserved for later treatment in more depth of the pattern and problems of the movement of coal to the electric utility market.

1/ Actually these statistics were assembled only for the year 1957, after which they were made on a quarterly basis.

TABLE 2A - CHANGING PATTERNS OF DISTRIBUTION OF BITUMINOUS COAL
BY TYPE OF USER AND BY REGION, 1957-1963
COAL COMPETITIVE AREAS

(000 Tons)

Geographic Region and Type of User	1957	1958	1959	1960	1961	1962	1963
New England	11,909	10,871	11,150	9,313	9,674	9,997	10,017
Electric Utilities	6,012	5,768	6,336	6,000	6,723	7,225	7,770
Coke & Gas Plants	1,345	995	1,090	570	475	456	472
Retail Dealers	1,279	880	558	623	453	450	300
All Other	3,273	3,228	3,166	2,120	2,023	1,866	1,475
Middle Atlantic	92,596	74,836	75,082	76,173	72,076	76,107	79,492
Electric Utilities	31,662	28,341	29,800	30,610	30,761	33,092	34,300
C. & G.	38,448	26,024	25,613	26,904	23,765	24,047	26,138
R. D.	2,498	2,819	1,883	1,781	1,641	1,539	1,357
A. O.	19,988	17,652	17,786	16,878	15,909	17,429	17,697
East North Central	170,697	147,238	161,242	158,125	151,278	159,391	164,423
Electric Utilities	66,436	61,822	68,360	69,572	68,199	74,750	78,944
C. & G.	38,757	26,011	30,103	30,709	27,127	26,496	27,709
R. D.	21,321	19,257	19,333	17,508	16,197	15,956	14,222
A. O.	44,183	40,148	43,446	40,336	39,755	42,189	43,548
West North Central	20,824	19,702	21,023	22,571	20,920	22,520	23,242
Electric Utilities	8,278	8,364	9,152	10,541	10,254	12,218	13,179
C. & G.	1,518	1,041	1,131	945	592	768	776
R. D.	4,079	3,858	4,051	4,125	3,651	3,261	2,602
A. O.	6,949	6,439	6,689	6,960	6,423	6,273	6,685
South Atlantic	52,560	49,789	50,682	52,547	55,316	57,891	63,816
Electric Utilities	22,251	22,734	26,334	27,167	29,825	31,951	35,977
C. & G.	11,321	9,561	7,596	8,441	8,307	8,316	9,008
R. D.	4,765	4,859	3,561	3,713	3,160	3,334	3,203
A. O.	14,223	12,635	13,191	13,226	14,024	14,290	15,628
East South Central	43,283	36,479	38,907	41,556	40,771	42,709	47,418
Electric Utilities	23,572	21,689	24,437	26,534	27,116	28,862	32,436
C. & G.	10,380	7,585	8,065	8,391	7,241	7,300	7,641
R. D.	2,494	2,496	1,904	1,959	1,863	1,810	1,999
A. O.	6,837	4,709	4,501	4,672	4,551	4,737	5,342
Mountain	8,779	7,362	7,346	8,536	8,932	8,898	10,823
Electric Utilities	1,437	1,541	2,327	2,780	3,407	3,788	5,832
C. & G.	3,772	2,830	2,297	3,050	2,886	2,297	2,465
R. D.	1,350	1,291	1,154	1,167	1,117	1,193	1,122
A. O.	2,220	1,700	1,568	1,539	1,522	1,620	1,404
Total Coal Competitive Regions	400,648	346,277	365,432	368,821	358,967	377,513	399,231
Electric Utilities	159,648	150,259	166,746	173,204	176,285	191,886	208,438
C. & G.	105,541	74,047	75,895	79,010	70,393	69,670	74,209
R. D.	37,786	35,460	32,444	30,876	28,082	27,543	24,805
A. O.	97,673	86,511	90,347	85,731	84,207	88,404	91,7[illegible]

TABLE 2B - CHANGING PATTERNS OF DISTRIBUTION OF BITUMINOUS COAL
BY TYPE OF USER AND BY REGION, 1957-1963
COAL COMPETITIVE AREAS

(1957 = 100)

Geographic Region and Type of User	1958	1959	1960	1961	1962	1963
New England	91.3	93.6	78.2	81.2	83.9	84.1
Electric Utilities	95.9	105.4	99.8	111.8	120.2	129.2
Coke & Gas Plants	74.0	81.0	42.4	35.3	33.9	35.1
Retail Dealers	68.8	43.6	48.7	35.4	35.2	23.5
All Other	98.6	96.7	64.8	61.8	57.0	45.1
Middle Atlantic	80.8	81.1	82.3	77.8	82.2	85.8
Electric Utilities	89.5	94.1	96.7	97.2	104.5	108.3
C. & G.	67.7	66.6	70.0	61.8	62.5	68.0
R. D.	112.9	75.4	71.3	65.7	61.6	54.3
A. O.	88.3	89.0	84.4	79.6	87.2	88.5
East North Central	86.3	94.5	92.6	88.6	93.4	96.3
Electric Utilities	93.1	102.9	104.7	102.7	112.5	118.8
C. & G.	67.1	77.7	79.2	70.0	68.4	71.5
R. D.	90.3	90.7	82.1	76.0	74.8	66.7
A. O.	90.9	98.3	91.3	90.0	95.5	98.6
West North Central	94.6	101.0	108.4	100.5	108.1	111.6
Electric Utilities	101.0	110.6	127.3	123.9	147.6	159.2
C. & G.	68.6	74.5	62.3	39.0	50.6	51.1
R. D.	94.6	99.3	101.1	89.5	79.9	63.8
A. O.	92.7	96.3	100.2	92.4	90.3	96.2
South Atlantic	94.7	96.4	100.0	105.2	110.1	121.4
Electric Utilities	102.2	118.3	122.1	134.0	143.6	161.7
C. & G.	84.5	67.1	74.6	73.4	73.5	79.6
R. D.	102.0	74.7	77.9	66.3	70.0	67.2
A. O.	88.8	92.7	93.0	98.6	100.5	109.9
East South Central	84.3	89.9	96.0	94.2	98.7	109.6
Electric Utilities	92.0	103.7	112.6	115.0	122.4	137.6
C. & G.	73.1	77.7	80.8	69.8	70.3	73.6
R. D.	100.1	76.3	78.5	74.7	72.6	80.2
A. O.	68.9	65.8	68.3	66.6	69.3	78.1
Mountain	83.9	83.7	97.2	101.7	101.4	123.3
Electric Utilities	107.2	161.9	193.5	237.1	263.6	405.8
C. & G.	75.0	60.9	80.9	76.5	60.9	65.3
R. D.	95.6	85.5	86.4	82.7	88.4	83.1
A. O.	76.6	70.6	69.3	68.6	73.0	63.2
Total Coal Competitive Regions	86.4	91.2	92.1	89.6	94.2	99.6
Electric Utilities	94.1	104.4	108.5	110.4	120.2	130.6
C. & G	70.2	71.9	74.9	66.7	66.0	70.3
R. D.	93.8	85.9	81.7	74.3	72.9	65.6
A. O.	88.6	92.5	87.8	86.2	90.5	94.0

In the seven-year period total coal changes in distribution, by regions, have been these:

Region	Percent Total Coal-Competitive Tonnage 1957	1963	Tonnage Change 1957 to 1963 Gain	Loss	Percent Change Since 1957 Increase	Decrease
New England	3.0	2.5	-	1,892	-	15.9
Middle Atlantic	23.1	19.9	-	13,104	-	14.2
East North Central	42.6	41.2	-	6,274	-	3.7
West North Central	5.2	5.8	2,418	-	11.6	-
South Atlantic	13.1	16.0	11,256	-	21.4	-
East South Central	10.8	11.9	4,135	-	9.6	-
Mountain	2.2	2.7	2,044	-	23.3	-
TOTAL	100.0	100.0	19,853	21,270	-	0.4

The changing distribution pattern for each of the categories we will discuss follows:

ELECTRIC UTILITIES

Region	Percent Total Coal-Competitive Tonnage 1957	1963	Tonnage Change 1957 to 1963 Gain	Loss	Percent Change Since 1957 Increase	Decrease
New England	3.8	3.7	1,758	-	29.2	-
Middle Atlantic	19.8	16.5	2,638	-	8.3	-
East North Central	41.6	37.9	12,508	-	18.8	-
West North Central	5.2	6.3	4,901	-	59.2	-
South Atlantic	13.9	17.3	13,726	-	61.7	-
East South Central	14.8	15.6	8,864	-	37.6	-
Mountain	6.9	2.7	4,395	-	305.8	-
TOTAL	100.0	100.0	48,790	-	30.6	-

The largest consumption increases among the users of coal have been in the electric utilities, the only consumption category which has seen an increase in each of the seven regions. However, the New England, Middle Atlantic, and East North Central regions, the only ones with decreases in total distribution, show the smallest increases in utility consumption.

Before discussing the transportation of utility coal in greater depth, the regional distribution breakdown for the other major consumer groups will be shown and briefly treated.

COKE AND GAS PLANTS

Region	Percent Total Coal-Competitive Tonnage 1957	1963	Tonnage Change 1957 to 1963 Gain	Loss	Percent Change Since 1957 Increase	Decrease
New England	1.3	.7	-	873	-	64.9
Middle Atlantic	36.5	35.2	-	12,310	-	32.0
East North Central	36.7	37.3	-	11,048	-	28.5
West North Central	1.4	1.1	-	742	-	48.9
South Atlantic	10.7	12.1	-	2,313	-	20.4
East South Central	9.8	10.3	-	2,739	-	26.4
Mountain	3.6	3.3	-	1,307	-	34.7
TOTAL	100.0	100.0	-	31,332	-	29.7

The fact that during this period distribution of coking coal was down 29.7 percent, whereas the total consumption in all four groups was down by slightly more than four-tenths of one percent, can be attributed to a large extent to the increased efficiency in the use of coal in the steel-making process. An exact measurement of this in isolation from other factors causing the decline would be difficult.

RETAIL DELIVERIES

Region	Percent Total Coal-Competitive Tonnage 1957	Percent Total Coal-Competitive Tonnage 1963	Tonnage Change 1957 to 1963 Gain	Tonnage Change 1957 to 1963 Loss	Percent Change Since 1957 Increase	Percent Change Since 1957 Decrease
New England	3.4	1.2	-	979	-	76.5
Middle Atlantic	6.6	5.5	-	1,141	-	45.7
East North Central	56.4	57.3	-	7,099	-	33.3
West North Central	10.8	10.5	-	1,477	-	36.2
South Atlantic	12.6	12.9	-	1,562	-	32.8
East South Central	6.6	8.1	-	495	-	19.8
Mountain	3.6	4.5	-	228	-	16.9
TOTAL	100.0	100.0	-	12,981	-	34.4

The general decline in retail deliveries over this period is independent of mode of transport employed. On the other hand, as will be discussed later, the growth in utility consumption, as brought out in the distribution data, has been affected, either directly or indirectly, by the means of transportation.

GENERAL INDUSTRY

Region	Percent Total Coal-Competitive Tonnage 1957	Percent Total Coal-Competitive Tonnage 1963	Tonnage Change 1957 to 1963 Gain	Tonnage Change 1957 to 1963 Loss	Percent Change Since 1957 Increase	Percent Change Since 1957 Decrease
New England	3.4	1.6	-	1,798	-	44.9
Middle Atlantic	20.5	19.3	-	2,291	-	11.5
East North Central	45.1	47.4	-	635	-	1.4
West North Central	7.1	7.3	-	264	-	3.8
South Atlantic	14.6	17.0	1,405	-	9.9	-
East South Central	7.0	5.8	-	1,495	-	21.9
Mountain	2.3	1.6	-	816	-	36.8
TOTAL	100.0	100.0	1,405	7,299	-	6.0

This is an important market for coal, but one where the constituent elements are quite diverse and where transportation patterns are less significant than in the distribution of utility coal. Yet in 1964 to the mine operators alone this field will be worth in excess of half-a-billion dollars.

Competition from other sources of energy, particularly from oil, underlies some of these changes. This is especially true in the New England, Middle Atlantic and East South Central regions which, in 1957, accounted for 30.9 percent of all consumption. By 1963 this figure had dropped to 26.7 percent. Reduced costs of transportation, such as are made possible through the operation of unit trains, have not yet been applied to this market area, to a large degree due to the heterogeneous character of demand.

For obvious reasons, we will not examine the remaining markets for coal, Canadian and overseas exports, which do not lend themselves to transportation as developed in this paper.

The last half of this paper will examine 1957-1963 trends in the distribution of coal by mode of transportation, excluding the coal pipeline, and will conclude with an analysis of the manner in which utility coal has been shipped. Because we have more complete data on the electric utility market for coal, distribution for this market has been assigned a major role in this report. Also, fortunately, we have excellent statistics covering railway and barge movements of utility coal. These two methods of transportation account for the bulk of utility movements.

TABLE 3A
CHANGING PATTERNS OF DISTRIBUTION OF BITUMINOUS COAL (ALL USERS), BY METHOD OF TRANSPORTATION AND BY REGION, 1957-1963
COAL COMPETITIVE AREAS (EXCLUDES WEST SOUTH CENTRAL AND PACIFIC)

Geographic Region	Thousands of Net Tons						
Method of Movement	1957	1958	1959	1960	1961	1962	1963
New England	11,909	10,871	11,150	9,313	9,674	9,997	10,017
All-rail	4,161	3,643	4,310	4,038	4,373	4,458	3,644
Tidewater	7,748	7,228	6,840	5,275	5,301	5,539	6,373
Middle Atlantic	92,596	74,836	75,082	76,173	72,076	76,107	79,492
All-rail	40,566	32,445	35,530	35,102	34,132	36,889	35,513
River & Ex-River	23,348	17,082	16,638	17,718	16,519	17,262	19,353
Great Lakes	4,505	3,694	2,200	2,490	2,385	2,711	2,443
Tidewater	12,372	11,551	10,994	11,220	10,355	9,144	11,215
Truck	10,255	7,988	9,720	9,643	6,928	10,101	10,968
Tramway, Conveyor, & Private Railroad	1,550	2,076	-	-	1,757	-	-
East North Central	170,697	147,238	161,242	158,125	151,278	159,391	164,423
All-rail	96,146	78,679	82,241	77,224	69,267	73,778	76,775
River & Ex-River	29,701	26,707	29,898	31,271	33,767	35,381	34,625
Great Lakes	27,149	24,453	29,665	28,408	27,457	28,192	31,333
Truck	15,907	17,399	19,438	21,222	20,787	22,040	21,690
T.,C. & P.R.	1,794	-	-	-	-	-	-
West North Central	20,824	19,702	21,023	22,571	20,920	22,520	23,242
All-rail	11,777	10,705	11,472	12,542	11,124	12,189	12,657
River & Ex-River	2,575	2,854	3,492	3,469	3,882	4,135	4,278
Great Lakes	3,510	2,901	3,092	3,984	3,503	3,001	3,214
Truck	2,962	3,242	2,967	2,576	2,411	3,195	3,093
South Atlantic	52,560	49,789	50,682	52,547	55,316	57,891	63,816
All-rail	33,529	31,838	32,820	33,576	34,939	36,755	41,408
River & Ex-River	9,492	8,835	8,526	8,501	9,779	9,638	10,473
Tidewater	6,205	6,061	4,986	5,610	5,444	5,840	5,889
Truck	2,142	3,055	4,350	4,860	3,101	5,658	6,046
T., C. & P.R.	1,192	-	-	-	2,053	-	-
East South Central	43,283	36,479	38,907	41,556	40,771	42,709	47,418
All-rail	25,036	21,308	23,200	26,789	27,713	29,214	31,843
River & Ex-River	13,450	10,621	11,021	10,870	9,654	9,824	10,703
Truck	3,066	4,550	4,686	3,897	3,404	3,671	4,872
T., C. & P.R.	1,731	-	-	-	-	-	-
Mountain	8,779	7,362	7,346	8,536	8,932	8,898	10,823
All-rail	7,407	5,921	6,006	6,518	6,491	6,706	7,026
Truck	1,294	1,388	1,287	1,993	2,338	2,094	3,732
T., C. & P.R.	78	53	53	25	103	98	65
Total Coal Competitive Regions	400,648	346,277	365,432	368,821	358,967	377,513	399,231
All-rail	218,622	184,539	195,579	195,789	188,039	199,989	208,866
River & Ex-River	78,566	66,099	69,575	71,829	73,601	76,240	79,432
Great Lakes	35,164	31,048	34,957	34,882	33,345	33,904	36,990
Tidewater	26,325	24,840	22,820	22,105	21,100	20,523	23,477
Truck	35,626	37,622	42,448	44,191	38,969	46,759	50,401
T., C. & P.R.	6,345	2,129	53	25	3,913	98	65

TABLE 3B
CHANGING PATTERNS OF DISTRIBUTION OF BITUMINOUS COAL (ALL USERS),
BY METHOD OF TRANSPORTATION AND BY REGION, 1957-1963
COAL COMPETITIVE AREAS (EXCLUDES WEST SOUTH CENTRAL AND PACIFIC)

Geographic Region	Index, 1957=100.0						
Method of Movement	1957	1958	1959	1960	1961	1962	1963
New England	100.0	91.3	93.6	78.2	81.2	83.9	84.1
All-rail		87.6	103.6	97.0	105.1	107.1	87.6
Tidewater		93.3	88.3	68.1	68.4	71.5	82.3
Middle Atlantic	100.0	80.8	81.1	82.3	77.8	82.2	85.8
All-rail		80.0	87.6	86.5	84.1	90.9	87.5
River & ex-river		73.2	71.3	75.9	70.8	73.9	82.9
Great Lakes		82.0	48.8	55.3	52.9	60.2	54.2
Tidewater		93.4	88.9	90.7	83.7	73.9	90.6
Truck		)85.3	82.3	81.7	73.6	85.6	92.9
T.,C.& P.R.		)					
East North Central	100.0	86.3	94.5	92.6	88.6	93.4	96.3
All-rail		81.8	85.5	80.3	72.0	76.7	79.9
River & ex-river		89.9	100.7	105.3	113.7	119.1	116.6
Great Lakes		90.1	109.3	104.6	101.1	103.8	115.4
Truck		)98.3	109.8	119.9	117.4	124.5	122.5
T.,C.& P.R.		)					
West North Central	100.0	94.6	101.0	108.4	100.5	108.1	111.6
All-rail		90.9	97.4	106.5	94.5	103.5	107.5
River & ex-river		110.8	135.6	134.7	150.8	160.6	166.1
Great Lakes		82.6	88.1	113.5	99.8	85.5	91.6
Truck		109.5	100.2	87.0	81.4	107.9	104.4
South Atlantic	100.0	94.7	96.4	100.0	105.2	110.1	121.4
All-rail		95.0	97.9	100.1	104.2	109.6	123.5
River & ex-river		93.1	89.8	89.6	103.0	101.5	110.3
Tidewater		97.7	80.4	90.4	87.7	94.1	94.9
Truck		)91.6	130.5	145.8	154.6	169.7	181.3
T.,C.& P.R.		)					
East South Central	100.0	84.3	89.9	96.0	94.2	98.7	109.6
All-rail		85.1	92.7	107.0	110.7	116.7	127.2
River & ex-river		79.0	81.9	80.8	71.8	73.0	79.6
Truck		)94.9	97.7	81.2	71.0	76.5	101.6
T.,C.& P.R.		)					
Mountain	100.0	83.9	83.7	97.2	101.7	101.4	123.3
All-rail		79.9	81.1	88.0	87.6	90.5	94.9
Truck		)105.0	97.7	147.1	177.9	159.8	276.7
T.,C.& P.R.		)					
Total Coal Competitive Regions	100.0	86.4	91.2	92.1	89.6	94.2	99.6
All-rail		84.4	89.5	89.6	86.0	91.5	95.5
River & ex-river		84.1	88.6	91.4	93.7	97.0	101.1
Great Lakes		88.3	99.4	99.2	94.8	96.4	105.2
Tidewater		94.4	86.7	84.0	80.2	78.0	89.2
Truck		)94.7	101.3	105.3	102.2	111.6	120.2
T.,C.& P.R.		)					

First taking our coal-competitive states as a whole, all-rail has not quite held its own since 1957, with 95.5 percent of the movement in 1963. 1/ However, the 1963 percentage vs. 1957 is better than that of any of the intervening years. On the other hand both "River and Ex-River" (part rail - part water) and "Great Lakes" movements have strongly increased their traffic in coal since 1958, after a dip from 1957 levels.

The trucking of coal in the over-all picture has risen by one-fifth since 1957, with a strong and consistent increase, though reversals in the rate of climb were experienced in 1958 and 1961. Until 1962, coal consumption through tidewater delivery had been declining. By the development of volume movements for utilities waterway operators jumped from 78.0 to 89.2 percent of 1957. Undoubtedly much of this was at the expense of the rails though exact measures of impact are not available.

The following regional summaries of trends by mode of transport reflect the changes which are taking place in the consumption of coal, both geographically and as between regions.

ALL-RAIL

Region	Percent Total Coal-Competitive Tonnage 1957	1963	Tonnage Change 1957 to 1963 Gain (000)	Loss (000)	Percent Change Since 1957 Increase	Decrease
New England	1.9	1.7	-	517	-	12.4
Middle Atlantic	18.6	17.0	-	5,053	-	12.5
East North Central	43.9	36.8	-	19,371	-	20.1
West North Central	5.4	6.1	880	-	7.5	-
South Atlantic	15.3	19.8	7,879	-	23.5	-
East South Central	11.5	15.2	6,807	-	27.2	-
Mountain	3.4	3.4	-	381	-	5.1
TOTAL	100.0	100.0	-	9,756	-	4.5

The largest rail loss in volume occurred in the East North Central Region, where the erosion in traffic reached 19,371,000 tons, or a fall-off of 7.1 percentage points in the proportion to total in this largest region with respect to rail traffic. As noted later, most of this loss went to river and ex-river. The growth in water transport of coal in this heavy rail traffic region can be assigned in large part to inter-energy competitive forces.

The gain in rail traffic in the South Atlantic and East South Central Regions, a combined "plus" of 8.2 percentage points, is largely attributable to volume movement of coal in trainloads.

RIVER AND EX-RIVER MOVEMENTS

Only five of the seven regions have river transportation. Of the other two, New England has tidewater movements while the Mountain Region has no water transportation of any kind.

River and ex-river movements of the five regions are shown for the seven-year span in the table below. These movements gained in three of the five regions, with the gains in the East North Central States, as noted above, roughly equal to their

1/ We have firm data for only the first half of 1964. Trends since the introduction of the unit train will be discussed at a later point.

loss in rail importance. A substantial loss in river and ex-river importance in the East South Central Region just about equalled its rise in rail proportions. Obviously the services offered by the railroads and generally favorable rates have siphoned off much of this business.

RIVER AND EX-RIVER

Region	Percent Total Coal-Competitive Tonnage 1957	1963	Tonnage Change 1957 to 1963 Gain (000)	Loss (000)	Percent Change Since 1957 Increase	Decrease
Middle Atlantic	29.7	24.3	-	3,995	-	17.1
East North Central	37.8	43.6	4,924	-	16.6	-
West North Central	3.3	5.4	1,703	-	66.1	-
South Atlantic	12.1	13.2	981	-	10.3	-
East South Central	17.1	13.5	-	2,747	-	20.4
TOTAL	100.0	100.0	866	-	1.1	-

GREAT LAKES MOVEMENTS

The chief point of significance in the Great Lakes figures is the substantial growth in the East North Central volume. As pointed out above, rail traffic has declined in relative importance in this area, while river and ex-river importance has increased to a lesser extent but still showing a very important growth. While hardly a revolution in transportation, the switch is most pronounced. As will be pointed out later, much of this increase in water movement has been in utility coal.

GREAT LAKES

Region	Percent Total Coal-Competitive Tonnage 1957	1963	Tonnage Change 1957 to 1963 Gain (000)	Loss (000)	Percent Change Since 1957 Increase	Decrease
Middle Atlantic	12.8	6.6	-	2,062	-	45.8
East North Central	77.2	84.7	4,184	-	15.4	-
West North Central	10.0	8.7	-	296	-	8.4
TOTAL	100.0	100.0	1,826	-	5.2	-

TIDEWATER MOVEMENTS

In the case of tidewater transportation of coal, the only three regions with such movements showed decreases ranging from 5.1 percent for the South Atlantic states to 17.7 percent in the New England states. While there was a small adjustment in the seven-year period in the proportion of tidewater traffic by region, overall decreases were experienced throughout the tidewater area.

TIDEWATER

Region	Percent Total Coal-Competitive Tonnage 1957	1963	Tonnage Change 1957 to 1963 Gain (000)	Loss (000)	Percent Change Since 1957 Increase	Decrease
New England	29.4	27.1	-	1,375	-	17.7
Middle Atlantic	47.0	47.8	-	1,157	-	9.4
South Atlantic	23.6	25.1	-	316	-	5.1
TOTAL	100.0	100.0	-	2,848	-	10.8

TRUCK, TRAMWAY AND CONVEYOR MOVEMENTS

Unfortunately it is not possible to separate truck movements from tramway and conveyor in all of the regions. However, truck operations considerably exceed those of the other two types. In 1957, 41,971,000 tons were transported by the three media, or 10.5 percent of total movement. By 1963 the total was 50,466,000, or 12.6 percent of over-all traffic. The significant fact is that in all regions except New England, and that by a small decrease, traffic expanded, with the largest growths in the East North Central, South Atlantic, and Mountain Regions.

The important newer developments in the transportation of coal - the unit train, the coal pipeline, and volume movements - have all been associated with the shipment of coal for use by the electric utility industry. This section of the report reinforces the earlier sections by showing how the utilities have participated in the changing transportation pattern. In fact, because of its size among the customers of coal, the utility industry's experience with transportation actually did much to establish the over-all pattern.

Table 4 below covers the methods of distributing utility coal, by region of destination, for the period 1957-1963.

TABLE 4A
ELECTRIC UTILITY COAL, PATTERNS OF DISTRIBUTION,
BY METHOD OF TRANSPORTATION AND BY REGION, 1957-1963
COAL COMPETITIVE AREAS (EXCLUDES WEST SOUTH CENTRAL AND PACIFIC)

Geographic Region Method of Movement	1957	1958	1959	1960	1961	1962	1963
	Thousands of Net Tons						
New England	6,012	5,768	6,336	6,000	6,723	7,225	7,770
All-rail	1,607	1,199	2,081	2,313	2,875	3,005	2,430
River & ex-river	-	-	-	-	-	-	-
Great Lakes	-	-	-	-	-	-	-
Tidewater	4,405	4,569	4,255	3,687	3,848	4,220	5,340
Truck	-	-	-	-	-	-	-
T.,C.& P.R.	-	-	-	-	-	-	-
Middle Atlantic	31,662	28,341	29,800	30,610	30,761	33,092	34,300
R.R.	13,136	11,951	13,282	14,001	15,402	17,433	17,414
River	2,017	2,023	2,004*	2,196	2,257	2,291	2,303
Great Lakes	2,053	1,434	1,271*	1,143	812	1,269	881
Tidewater	9,058	8,084	8,289	8,900	8,605	7,459	8,801
Truck	)5,398	3,333	4,954	4,370	2,409	4,640	4,901
T.,C.& P.R.	)	1,516			1,276		
East North Central	66,436	61,822	68,360	69,572	68,199	74,750	78,944
R.R.	28,144	23,811	23,509	22,389	20,222	23,180	26,123
River	19,087	19,185	21,343	23,209	25,471	27,247	27,273
Great Lakes	11,940	10,707	13,434	12,607	11,465	12,726	14,467
Tidewater	-	-	-	-	-	-	-
Truck	5,533	)8,119	10,074	11,367	11,041	11,597	11,081
T.,C.& P.R.	1,732	)					
West North Central	8,278	8,364	9,152	10,541	10,254	12,218	13,179
R.R.	5,011	4,219	5,070	6,036	5,689	6,562	7,145
River	1,781	2,235	2,760	3,004	3,359	3,636	3,785
Great Lakes	685	840	539	987	791	759	751
Tidewater	-	-	-	-	-	-	-
Truck	801	1,070	783	514	415	1,261	1,498
T.,C.& P.R.	-	-	-	-	-	-	-
South Atlantic	22,251	22,734	26,334	27,167	29,825	31,951	35,977
R.R.	15,615	16,426	18,314*	18,309*	19,563*	21,418	25,133
River	3,231	3,262	3,342	3,754	4,754	4,828	4,917
Great Lakes	-	-	-	-	-	-	-
Tidewater	1,437	1,572	1,491*	1,465*	1,414*	1,388	1,485
Truck	1,198	1,474	3,187	3,639	2,167	4,317	4,442
T.,C.& P.R.	770	-	-	-	1,927	-	-
East South Central	23,572	21,689	24,437	26,534	27,116	28,862	32,436
R.R.	9,158	9,491	11,640	14,479	16,638	18,036	19,963
River	11,178	8,545	9,144	9,079	7,823	8,081	8,756
Great Lakes	-	-	-	-	-	-	-
Tidewater	-	-	-	-	-	-	-
Truck	1,505	3,653	3,653	2,976	2,655	2,745	3,717
T.,C.& P.R.	1,731	-	-	-	-	-	-

* Estimated from incomplete data.

TABLE 4A - Cont'd.

ELECTRIC UTILITY COAL, PATTERNS OF DISTRIBUTION, BY METHOD OF TRANSPORTATION AND BY REGION, 1957-1963

COAL COMPETITIVE AREAS (EXCLUDES WEST SOUTH CENTRAL AND PACIFIC)

Geographic Region	Thousands of Net Tons						
Method of Movement	1957	1958	1959	1960	1961	1962	1963
Mountain	1,437	1,541	2,327	2,780	3,407	3,788	5,832
R.R.	1,103	938	1,702	1,455	1,621	2,190	2,545
River	-	-	-	-	-	-	-
Great Lakes	-	-	-	-	-	-	-
Tidewater	-	-	-	-	-	-	-
Truck	298	550	572	1,300	1,683	1,500	3,222
T.,C.& P.R.	36	53	53	25	103	98	65
Total Coal Competitive Regions	159,648	150,259	166,746	173,204	176,285	191,886	208,438
All-rail	73,774	68,035	75,598	78,982	82,010	91,824	100,753
River & ex-river	37,294	35,250	38,593	41,242	43,664	46,083	47,034
Great Lakes	14,678	12,981	15,244	14,737	13,068	14,754	16,099
Tidewater	14,900	14,225	14,035	14,052	13,867	13,067	15,626
Truck	14,733	19,715	23,223	24,166	20,370	26,060	28,861
T.,C.& P.R.	4,269	53	53	25	3,306	98	65

TABLE 4B

Index, 1957=100.0

New England	100.0	95.9	105.4	99.8	111.8	120.2	129.2
All-rail	100.0	74.6	129.5	143.9	178.9	187.0	151.2
River & ex-river	-	-	-	-	-	-	-
Great Lakes	-	-	-	-	-	-	-
Tidewater	100.0	103.7	96.6	83.7	87.4	95.8	121.2
Truck	-	-	-	-	-	-	-
T.,C.& P.R.	-	-	-	-	-	-	-
Middle Atlantic	100.0	89.5	94.1	96.7	97.2	104.5	108.3
R.R.	100.0	91.0	101.1	106.6	117.3	132.7	132.6
River	100.0	100.3	99.4	108.9	111.9	113.6	114.2
Great Lakes	100.0	69.8	61.9	55.7	39.6	61.8	42.9
Tidewater	100.0	89.2	91.5	98.3	95.0	82.3	97.2
Truck	)100.0	89.8	91.8	81.0	68.3	86.0	90.8
T.,C.& P.R.	)						
East North Central	100.0	93.1	102.9	104.7	102.7	112.5	118.8
R.R.	100.0	84.6	83.5	79.6	71.9	82.4	92.8
River	100.0	100.5	111.8	121.6	133.4	142.8	142.9
Great Lakes	100.0	89.7	112.5	105.6	96.0	106.6	121.2
Tidewater	-	-	-	-	-	-	-
Truck	)100.0	111.8	138.7	156.5	152.0	159.6	152.5
T.,C.& P.R.	)						

TABLE 4B - Cont'd.
ELECTRIC UTILITY COAL, PATTERNS OF DISTRIBUTION,
BY METHOD OF TRANSPORTATION AND BY REGION, 1957-1963
COAL COMPETITIVE AREAS (EXCLUDES WEST SOUTH CENTRAL AND PACIFIC)

Geographic Region Method of Movement	Index, 1957=100.0 1957	1958	1959	1960	1961	1962	1963
West North Central	100.0	101.0	110.6	127.3	123.9	147.6	159.2
R.R.	100.0	84.2	101.2	120.5	113.5	131.0	142.6
River	100.0	125.5	155.0	168.7	188.6	204.2	212.5
Great Lakes	100.0	122.6	78.7	144.1	115.5	110.8	109.6
Tidewater	-	-	-	-	-	-	-
Truck	100.0	133.6	97.8	64.2	51.8	157.4	187.0
T.,C.& P.R.	-	-	-	-	-	-	-
South Atlantic	100.0	102.2	118.3	122.1	134.0	143.6	161.7
R.R.	100.0	105.2	117.3	117.3	125.3	137.2	161.0
River	100.0	101.0	103.4	116.2	147.1	149.4	152.2
Great Lakes	-	-	-	-	-	-	-
Tidewater	100.0	109.4	103.8	101.9	98.4	96.6	103.3
Truck	100.0	74.9	161.9	184.9	208.0	219.4	225.7
T.,C.& P.R.	-	-	-	-	-	-	-
East South Central	100.0	92.0	103.7	112.6	115.0	122.4	137.6
R.R.	100.0	103.6	127.1	158.1	181.7	196.9	218.0
River	100.0	76.4	81.8	81.2	70.0	72.3	78.3
Great Lakes	-	-	-	-	-	-	-
Tidewater	-	-	-	-	-	-	-
Truck	100.0	112.9	112.9	92.0	82.0	84.8	114.9
T.,C.& P.R.	-	-	-	-	-	-	-
Mountain	100.0	107.2	161.9	193.5	237.1	263.6	405.8
R.R.	100.0	85.0	154.3	131.9	147.0	198.5	230.7
River	-	-	-	-	-	-	-
Great Lakes	-	-	-	-	-	-	-
Tidewater	-	-	-	-	-	-	-
Truck	100.0	180.5	187.1	396.7	534.7	478.4	984.7
T.,C.& P.R.	-	-	-	-	-	-	-
Total Coal Competitive Regions	100.0	94.1	104.4	108.5	110.4	120.2	130.6
All-rail	100.0	92.2	102.5	107.1	111.2	124.5	136.6
River & ex-river	100.0	94.5	103.5	110.6	117.1	123.6	126.1
Great Lakes	100.0	88.4	103.9	100.4	89.0	100.5	109.7
Tidewater	100.0	95.5	94.2	94.3	93.1	87.7	104.9
Truck	-	-	-	-	-	-	-
T.,C.& P.R.	-	-	-	-	-	-	-

Source: Bituminous Coal and Lignite Distribution, Branch of Coal Economics, Division of Coal, Bureau of Mines, U. S. Department of the Interior.

A breakdown of regional receipts by mode of transportation highlights the seven-year changes which have taken place in the distribution landscape.

ALL-RAIL MOVEMENTS

Region	Percent of Total Utility Movement 1957	Percent of Total Utility Movement 1963	Percent Change over 1957 Increase	Percent Change over 1957 Decrease
New England	2.2	2.4	51.2	-
Middle Atlantic	17.8	17.3	32.6	-
East North Central	38.1	25.9	-	7.2
West North Central	6.8	7.1	42.6	-
South Atlantic	21.2	25.0	61.0	-
East South Central	12.4	19.8	118.0	-
Mountain	1.5	2.5	130.7	-
TOTAL	100.0	100.0	36.6	-

The only decrease in utility tonnage was in the East North Central Region which saw this business drop 7.2 percent and slip from 38.1 percent to 25.9 percent of all utility shipments in coal-competitive regions. As will be shown below, utility volume in this region has shifted from rail to water.

The largest increase in volume in an important area was in the East South Central states, which saw a rise of 130.7 percent, with participation in the total rising from 12.4 percent in 1957 to 19.8 percent by 1963. A healthy increase also took place in the South Atlantic Region. Both of these areas have benefitted from volume rates and trainload movements, especially adapted to utility coal movement.

RIVER AND EX-RIVER MOVEMENTS

Region	Percent of Total Utility Movement 1957	Percent of Total Utility Movement 1963	Percent Change over 1957 Increase	Percent Change over 1957 Decrease
Middle Atlantic	5.4	4.9	14.2	-
East North Central	51.2	58.0	42.9	-
West North Central	4.8	8.0	112.5	-
South Atlantic	8.6	10.5	52.5	-
East South Central	30.0	18.6	-	21.7
TOTAL	100.0	100.0	26.1	-

These river and ex-river figures for utility coal show two significant though opposite trends. River movements in the East North Central Region were up 42.9 percent, with the region's participation in total utility shipments up from 51.2 percent to 58.0 percent. This is the area (Ohio, Indiana, Illinois, Wisconsin and Michigan) where the barging of utility coal has grown rapidly to facilitate the meeting of gas competition. Increased use of rail, though several contracts have already been consummated for volume movement in unitized trains, will not show up yet in recent or current figures.

On the other hand, movements by rail in the East South Central Region (Kentucky, Tennessee, Alabama and Mississippi) have increased at the expense of water, which has declined 21.7 percent and even more significantly now is responsible for only 18.6 percent of total movement, compared to 30.0 percent in 1957. Again, this movement is of utility coal and the railroads, both in service and cost, have worked with the shippers and receivers to make possible a low delivered price.

Only three regions have any Great Lakes coal movements, as set forth in the following tabulation:

GREAT LAKES MOVEMENTS

Region	Percent of Total Utility Movement		Percent Change over 1957	
	1957	1963	Increase	Decrease
Middle Atlantic	14.0	5.5	-	57.1
East North Central	81.3	89.9	21.2	-
West North Central	4.7	4.6	9.6	-
TOTAL	100.0	100.0	9.7	-

As shown above, substantial increases have taken place in rail and river movements. Much of this coal has been diverted from movement on the lakes.

While tidewater coal has slipped in the over-all picture, its importance in the movement of coal to New England has increased by 4.6 percentage points, matched by a nearly equal decrease to the Middle Atlantic area. Increased use of tidewater to New England is an important part of the efforts of the coal industry to market its product in an area where transport costs have been a barrier to entry.

TIDEWATER MOVEMENTS

Region	Percent of Total Utility Movement		Percent Change over 1957	
	1957	1963	Increase	Decrease
New England	29.6	34.2	21.2	-
Middle Atlantic	60.8	56.3	-	2.8
South Atlantic	9.6	9.5	3.3	-
TOTAL	100.0	100.0	4.9	-

Unfortunately, as true with utility movement as with total distribution truck statistics are not clear in the sense that: (1) tramway, conveyor, and private railroad data may be lumped in with truck figures, and (2) there is no apparent pattern used in assembling such information.

Keeping in mind the possible unreliability of such data in general, these statistics, based on the same distribution data of the Bureau of Mines used throughout this report, indicate the progress of truck transportation of coal over the seven years.

TRUCK MOVEMENTS 1/

Region	Percent of Total Utility Movement		Percent Change over 1957	
	1957	1963	Increase	Decrease
Middle Atlantic	28.4	16.9	-	9.2
East North Central	38.2	38.3	52.5	-
West North Central	4.2	5.2	87.0	-
South Atlantic	10.4	15.4	125.7	-
East South Central	17.0	12.8	14.9	-
Mountain	1.8	11.4	884.1	-
TOTAL	100.0	100.0	95.2	-

1/ Contains movements of tramways, conveyors and private railroads - 4,269,000 tons in 1957 and 65,000 tons in 1963. Separate break-outs of truck movements are not available.

The most significant change is in the East North Central area which while increasing movement 52.5 percent maintained its percentage share of the truck volume. It is this area where rail movement decreased substantially, largely eroding to water and motor transportation.

The next, and summary tabulation, shows the changes which have taken place in the share of each region's utility market by each mode of transportation.

CHANGE IN PERCENTAGE POINTS
IN SHARE OF UTILITY COAL VOLUME,
BY REGION, BY MEANS OF SHIPMENT,
1963 vs. 1957

Region	Rail	River and Ex-River	Great Lakes	Tidewater	Truck, etc.
New England	+ 0.2	-	-	+4.6	-
Middle Atlantic	- 0.5	- 0.5	-8.5	-4.5	-11.5
East North Central	-12.2	+ 6.8	+8.6	-	+ 0.1
West North Central	+ 0.3	+ 3.2	-0.1	-	+ 1.0
South Atlantic	+ 3.8	+ 1.9	-	-0.1	+ 5.0
East South Central	+ 7.4	-11.4	-	-	- 4.2
Mountain	+ 1.0	-	-	-	+ 9.6

Rail's major gains have generally been in the south, with water's chief advances in the north. Major loser with respect to all five forms of shipment has been the Middle Atlantic area. Minor truck transport gains have been experienced in four of the regions where coal is trucked.

Any realistic comparison of the cost to the coal shipper of using the various transportation techniques is not feasible. This is brought out in our description of each mode in its coal transportation function.

Rail transportation has long been the major method of getting coal from the mines to the market. The assembly, classification, line haul and distribution of coal has been without pattern of organization, especially as between coal-carrying roads. Rate differentials exist between operators with respect to sources and markets. However, this is not the place to be specific and to go into detail.

The one exception to date has been the transportation of utility coal. In order to permit the delivery of coal at the lowest price (cents per million b.t.u.'s) to meet competition from gas and oil, and undoubtedly in the future from nuclear power, two steps have been taken by coal producers, railroads, and utilities in cooperation, though of course, primarily by the first two: (1) guaranteed volume, and (2) unit train operations.

First to develop were guaranteed volumes, where the railroads would allow lower rates for a guaranteed annual tonnage. The utility would then take the tonnage, if the delivered price would be right.

This type of transportation has not gained the attention or the imagination of the public as has the "unitized train." Starting early in 1963, this type of rail movement offers low train-load rates for coal assembled from a very limited number of origins (mines) to one or two utility destinations. Rate reductions hinge on a number of considerations. A cut of from one-fourth to one-third represents the general range. The term "integral train" is sometimes used to describe this operation. No such train exists, except perhaps on the drawing boards. With such a train, equipment is special and the train exists as a unit not to be broken up. A typical movement, for example, as provided in one tariff, is three days from Western Pennsylvania to the New York-New Jersey industrial (utility) complex, heavy penalties for delay in unloading and a return trip in another three days. The true integral train is some time off. However, meanwhile the unitized train is helping the coal industry stem and in many instances reverse the erosion of its markets.

Water transportation has been instrumental in delivering low cost coal to utilities and industries on or near waterways. Statistics, other than those developed above, are scarce, especially with respect to cost. A relatively large volume of this traffic is classifiable as private transportation. This has been very effective in maintaining coal competitive in the Ohio-Mississippi system, as well as other river complexes.

In the years ahead, water transportation, especially on inland waterways, will be an increasingly effective weapon in coal's competition with gas and oil.

Truck transportation, the third of the standard modes, does not lend itself to cost or operating analysis. Again, this is a private operation, even more than water carriers. There is no common carrier movement of coal. With few or no detailed reports to be made to government, either federal or state, average length of haul, rates, volume, etc. are open to question. The only national figures are those reported to the Bureau of Mines, showing such information as has been set forth previously.

The role of truck transportation in the coal markets of 1970 and beyond cannot be assessed from this point.

The Coal Pipeline. Before concluding this paper, reference should be made to the coal pipeline. From its origin in 1957 to transport coal from Consolidation Coal Company's Georgetown mine at Cadiz, Ohio some 105 miles to the Cleveland Electric Illuminating Company's Eastlake Plant, the pipeline excited imagination. Operating costs have not been made public. The Ohio pipeline was deactivated in the fall of 1963, after having been operated for an estimated 700 million ton miles of coal, because railroad rates on the same coal were substantially reduced. It has been effectively demonstrated that this method of transportation is entirely feasible technically.

Tentative plans have been made, in one instance progressing to a point where attempts were made through the action of state legislatures to obtain eminent domain rights, to provide coal pipelines (1) from West Virginia to the New York-New Jersey industrial area, (2) from southern Illinois to Chicago, and (3) to the West Coast (California) from Utah and surrounding areas. However, until coal pipelines can secure eminent domain in interstate operations, a right now possessed by competing fuels, expansion of the pipeline will be seriously handicapped.

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There are many facets of coal transportation which we have not tapped, such as comparative costs as between transport modes and with respect to coal and competing fuels. To be reasonably adequate, in the case of coal such costs would have to be constructed rather than obtained from official records. Such data would not serve our purpose.

The transportation future for coal is a bright one. This is very favorable, as chief future reductions in the delivered price of coal will have to come from distribution rather than production.

MER/fm

ECONOMICS OF ENERGY TRANSPORTATION - PETROLEUM AND PETROLEUM PRODUCTS TRANSMISSION

By J. A. Horner, President
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INTRODUCTION

The transportation of petroleum and petroleum products is at the same time competitive and complementary...trucks compete with railroads and pipelines; pipelines compete with barges and tankers; tankers compete with barges, and so on. At the same time these competitors complement each other in that a single unit of petroleum energy, to achieve its most economical delivery, may be handled by as many as four separate transportation media from the wellhead to the consumers tank.

This complex transportation system supplies some 1-1/2 million tons (approximately 10.9 million barrels per day) of petroleum products daily to such diverse destinations as service stations, home heating tanks, public utilities, railroad fueling yards, ships' bunker tanks, and the nation's airports.

Oil today efficiently supplies 44 percent, per Table 1, of the nation's energy requirements. Some 50 percent of this is supplied to the so-called safe market--motive fuels. Here, severe competition between supplying companies within the oil industry provides every incentive for continuous improvement of transportation facilities. To supply and retain the other 50 percent of oil's energy market, the industry's competition is not only between the many supplying companies, but there is rigorous competition from other energy sources, mainly gas and coal.

Thus, there is not only great emphasis in our business on the economics of transportation, but there is the sheer necessity of competing in the market place if individual companies are to survive and prosper.

I. STATE OF DEVELOPMENT

This transportation of energy is in two parts: the collection at refineries of the crude oil from remote sources and the dispersion of products to the market. While unit transportation costs are low, they are significant and total approximately 2 cents per gallon at such destinations as New York, Chicago, and Los Angeles. Thus, the money to be saved by economical transportation is great, and the justification for investment in freight-saving facilities is correspondingly great.

The main facilities which effect this efficient transportation job form an impressive total as detailed in Table 2. Today's replacement cost minus depreciation is estimated at $7-1/2 billion; original gross investment is perhaps $5 to $6 billion.

In addition to the facilities included in the foregoing, petroleum utilizes such specialized distribution systems as pipeline fueling at seven major commercial airports and about fifty-two military air bases, dozens of marine terminals, pipelines for delivery to utilities and railroad yards, and pipelines for supplying heating oil direct to some 50,000 homes, mainly in housing developments.

Comparative use of petroleum's main transportation facilities and trends in such usage are listed in Table 3. Compared to 1940 and 1950, trucks and pipelines are handling a much larger share of petroleum tonnage delivered daily, but since 1955 the division of tonnage delivered has changed very little. Actually, a precise comparison of the work done by the different categories of transportation should include the distance hauled, with the tabulation expressed in ton-miles, but statistics on this basis are not available. It is evident, however, that since the pipeline and marine categories transport petroleum the longest distances, they thus perform the bulk of the ton-mile transportation job.

What are the economic forces which have led to this "state of development"? Basic, of course, is the competitive drive already noted, but the trends and improvements in new facilities reflect the economic impact of two major factors: (A) large-lot transport over maximum distance, (B) technological development including automation.

A. LARGE-LOT CONCEPT

Super tankers, large barge tows, jumbo tank cars, mammoth trucks, large diameter pipelines all testify to the simple economic fact that large quantities can be transported cheaper than small quantities--per ton. Costs are spread over more units. Extra handling is also minimized by the large trucks delivering direct from refineries and terminals to service stations and consumers, thus bypassing bulk depots. Table 4 illustrates the size of today's transportation equipment and how it compares with that of twenty years ago.

Amount of freight saved by the large-lot concept is illustrated in Table 5. Thus, for example, a new 47-M DWT tanker saves, roughly, 50 percent versus a new 16-M DWT T-2 type tanker (which is no longer economic to build) on the Gulf-New York run; a 24-inch diameter line saves about

60 percent versus a 10-inch line; a jumbo 20,000-gallon tank car can save 25 percent on a 1,000-mile haul versus a 10,000-gallon car; and an 8,500-gallon truck saves 15-30 percent on a 50-mile haul (100-mile round trip) versus a 6,500-gallon size.

Economic assessment of utilizing large equipment necessarily takes into account other factors than just the point to point freight saved. Specifically, the large-lot concept requires large tankage and inventory at delivering and receiving points. In the case of super tankers, it also requires deep berths, heavy piers, and rapid loading and unloading facilities. Terminal size and investment to service large marine equipment versus small are compared in an example in Table 6. This suggests that certain minimum throughputs must be achieved for the freight saved by the "large-lot" carrier to offset the extra cost of terminal facilities and inventory required for the big ships.

While the economic incentives behind the large-lot concept are, of course, age-old and not peculiar to oil, our industry is now able to exploit to a high degree the economies of the large-lot concept because of several developments: (1) sufficient underlying demands, (2) improvement of rivers and harbors, (3) improved highway system.

1. <u>Sufficient Underlying Demands</u>

Use of pipeline and marine transportation obviously depends on establishment of a minimum demand level, and for a minimum sized products pipeline of some 6-inch diameter and 100 miles long, such demand is roughly 10,000 barrels per day versus trucking. For a barge terminal, it is about 1,000 barrels per day versus trucking. Growth in population has brought combined product demand levels in more and more urban areas (and a 50-mile surrounding area) not only to these minima but also to the minima required to pay out pipelines versus marine transportation--where the latter is handicapped by a longer route or winter ice. Examples of the latter: West Shore Pipe Line (Chicago to Green Bay), Wolverine Pipe Line (Chicago to lake ports), Olympic Pipe Line (Puget Sound to Portland). Growth of demand for single, hard-to-handle products such as propane has also reached the point where volume makes pipeline transportation feasible. Texas Eastern, Mid-America and Dixie Pipe Lines are examples of common carrier pipelines now handling propane. Similarly, LPG tankers and barges have become feasible for coast-wise and inland waterway movement of propane.

2. Improvements of Rivers and Harbors

Extensive harbor improvements for the larger draft ocean tankers are programmed per Table 7. Examples:

	LARGEST TANKER (M DWT)		PROJECT
	NOW	FUTURE	COMPLETION DATE
New York	47	85	1967
San Francisco	38	85	1965

Through extensive work by the Federal Government during the 1930's, many of the inland rivers were opened to reasonable (9-foot) draft barge transportation, and, of course, barge terminals were established in coastal harbors and waterways. Two current barge projects of significance are (a) the lock enlargements on the Ohio River to 1,200 feet each (formerly 600 feet) to accommodate large tows, and (b) the John Day Dam on the Columbia, which will eliminate the present 7-foot draft bottleneck. Table 8 lists the current schedule of lock improvements on the Ohio.

Total Federal appropriations for navigation improvements alone (as distinguished from flood control and other purposes) were $225 million in 1963, rising from a low of $25 million in 1954, per Table 9 attached.

3. Improved Highways

Improved highways have permitted exploitation of the large-lot concept. Economics dictate that a $30,000 truck (some cost $50,000) spends maximum percent of its time in transit and minimum at loading and unloading point. The nation's super highways permit heavy loads, rapid transportation, and more miles per driver shift. 15,000 miles of the Federal interstate highways system were open to traffic in 1963. The over-all program totalling 41,000 miles is scheduled for completion by 1971.

Before passing on from this direct consideration of the large-lot concept, a realistic word concerning service requirements would be in order. Petroleum is a universal fuel, particularly for motive power, and demand levels in many sectors dictate less than jumbo size facilities. Consequently, there is a substantial requirement for providing optimum facilities, whether they be pipeline, truck or marine. Likewise the customers' facilities and policy toward inventory levels must be an important consideration in determining transportation facilities.

B. TECHNOLOGICAL DEVELOPMENTS

The nature of today's transportation facilities dramatically reflects technological advances in construction, maintenance, automation, operation, and auxiliary services. Exploitation of the large-lot delivery concept itself depends on such advances. Improvements range from better materials and more efficient prime movers to corrosion control and automated equipment.

In pipelines, the technological developments are first, faster and more economical pipe installation with such equipment as improved ditch diggers, in-the-field coating machines, in-the-field pipe fabricators, automatic welding, and X-ray inspection devices; second, higher tensile strength steel which has permitted reduction of pipe tonnage by 50 percent since 1948; third, improved product separation techniques through such devices as rubber spheres and motorized valves; fourth, improved metering of large capacities; fifth, development of lease automatic custody transfer equipment; sixth, improved telemetry and so-called push-button controls, permitting operation of entire pipelines from a central console; seventh, corrosion control by cathodic protection and improved coatings, both internal and external. Based on Interstate Commerce Commission statistics, reductions in pipeline personnel from 1952 to 1962 amounted to 50 percent of station labor, 35 percent of maintenance personnel, and 23 percent of gaugers.

In marine equipment the technological development of suitable wharves, hose handling rigs, and offshore moorings has been of perhaps greater importance in exploiting the large-lot concept than the mere (but not to be minimized) technology of building large, fast ships. Examples are the elaborate wharves and hose handling gear at industry wharves in New York Harbor, offshore mooring in 65 feet of water at Northville, Long Island, and crude oil loading facilities in the Louisiana Delta region and under development off the Louisiana shore in 75 feet of water. Improved centrifugal pumps, which also reduce cargo stripping time, have made significant reductions in vessel operating expense in recent years. Improved integrated barge tow configuration has significantly reduced drag and thus increased efficiency. On the Mississippi and Ohio Rivers mid-stream fueling and victualling have shortened in-port time, while radio and radar have speeded transit times. Significant automation developments in marine equipment are in engine room controls and remote handling of cargo. Manning scales on tankers are being reduced on the order of five men; from a range of thirty-five to forty previously to thirty to thirty-five in the future. Such reductions, and those which may be effected later through further mechanization or the transfer to shore staff of present-day shipboard functions (maintenance, cargo handling, etc.), will require the cooperation of the maritime unions. In the case of licensed personnel and watch standers, the approval of the U. S. Coast Guard will also be a requirement. Inland waterway operators have made greater progress in these areas than tanker operators; a typical 8,000-ton tow, for instance, with wheelhouse control of the engine room and in some cases revised galley arrangements, has nine crew men vs. twelve crew men ten years ago.

In tank cars the technological development of 20,000 and 30,000-gallon capacities has been a major breakthrough realized just in the last ten years. There is even a 50,000-gallon car which is utilized in restricted service. In the largest cars the tank itself supports the lading between the trucks, eliminating the center sill. This permits maximum utilization of larger capacity cars while staying within AAR clearance and weight restrictions. In recognition of reduced rail handling expense, the railroads are able to reduce rates by 25 to 40 percent or more for shipments in these cars. (Cf. 1,000-mile example in Table 5.)

In trucks the technology of large capacities has recently reached an all-time high in large-lot deliveries: 16,500 gallons per truck in Michigan. Such a truck has eleven axles. Size and weight are regulated by state law. In 1963, the last state, Pennsylvania, raised its weight limit to the generally accepted standard of 73,280 pounds--equivalent to 8,200 gallons of gasoline. A 6,500-gallon size was considered "large" only ten years ago.

Storage, whether for seasonal accumulation or for working terminal purposes, is a vital part of the transportation network. Technological developments have now provided: (a) relatively cheap seasonal storage for the volatile fuels and (b) much automation at working terminals. As to (a), ordinary steel pressure storage for butane and propane commonly costs $15 to $25 per barrel, but the underground or refrigerated storage developed in recent years costs only $1 to $8 per barrel in large sizes. A substantial amount of the latter, located near the market, is an attractive alternative to extra transportation capacity in the form of more tank cars, larger pipelines, more ships, and so forth, otherwise required to handle peak winter loads. As to (b), at working terminals there has been extensive automation in tank farm gauging devices, automatic custody transfer equipment, blending equipment, and automatic truck loading equipment. This latter has been developed to the point that the truck driver now handles all functions of product loading and metering. Such facilities add $25/50,000 to terminal capital, but rapid payouts are shown where volumes exceed 1,000 barrels per day.

II. COSTS

The economic effect of the large-lot deliveries and technological improvements noted in the preceding paragraphs is incorporated in the freight costs applicable to today's typical (as distinguished from largest) equipment. Considerably larger than twenty years ago, per Table 4, today's typical equipment comprises 25 M DWT tankers, 20 M barrel barges (60 M barrel tows), 10,000 gallon cars, 8,500 gallon trucks, and a wide range of pipeline diameters.

Industry's use of this particular equipment results in freight costs, including reasonable return on investment, which are tabulated according to mileage in Table 10. The wide range in rail and truck rates (often common carrier tariffs) is forced by the diverse competitive conditions which these carriers meet. For a 500-mile haul, the estimated rates are:

		AVERAGE	
	CENTS PER 500 BBL. MILES	¢/100 BBL. MILE	MILLS/ TON MILE
Pipeline	16-50	5.4	4.0
Tanker	12-15	2.7	2.0
Barge	14-18	3.3	2.5
Tank Car	85-180	27	20
Truck	160-340	46	35

If each of the foregoing transportation facilities is used over a distance for which it is reasonably well suited, the rates may be compared as follows:

	DISTANCE MILES	AVERAGE ¢/100 BBL. MILE	MILLS/ TON MILE
Pipeline	1,000	3.7	2.8
Tanker	2,200	1.6	1.2
Barge	500	3.3	2.5
Tank Car	1,000	23	18
Truck	50	46	35

It is seen from the foregoing that the costs per mile for movement via pipeline and water carriers are normally comparatively close. In practice, the selection of the facilities used must consider, among others, factors such as: the comparative length of the water and pipeline routes, the availability of navigable water, terminalling costs, winter icing problems, and opportunities for intermediate deliveries.

The percentage of costs which vary directly with occupancy has a profound effect on how equipment is utilized and how transportation systems are expanded. In the case of common carrier facilities where the shipper pays marine charter rates and common carrier tariffs, the direct costs coincide generally with the total costs. In the case of privately owned transportation facilities, however, the direct costs are significantly lower, and the cost differential between alternative modes of transportation is changed.

The proportion of fixed and direct costs among the transportation types is about as follows:

	PERCENT FIXED	PERCENT DIRECT
Pipeline	70-80	20-30
Tanker	20-40	60-80
Barge	30	70
Tank Car	Not applicable because shipper pays rail tariff.	
Private Truck	15-20	80-85

The higher the ratio of fixed to direct costs, the greater the premium on maximum utilization. Thus, tariffs in the case of common carrier pipelines, or shipping territories in the case of privately owned pipelines, are normally established so as to provide optimum utilization of the facility.

The effect of occupancy on transportation costs is recognized in the so-called "Dedicated Service" rates available from for-hire truckers. If, for example, the trucker is assured 120 hours per week utilization of his equipment, the reduction in rates may be 20 to 30 percent; 100 hours per week utilization, the reduction could be 15 to 20 percent; 80 hours per week utilization, the reduction may average 10 percent.

Large-lot delivery and technological improvements are also being utilized to lessen the effect of wage inflation on total transportation expense. The following tabulation shows the approximate percentage of wages in each type of transportation:

	PERCENT OF TOTAL COST WAGES
Pipeline	15
Tanker	30
Barge	35
Tank Car	Not applicable because shipper pays tariff.
Truck	50

Given two types of carrier with roughly the same costs, the oilman is likely to build or buy the one less susceptible to inflationary pressures. This is an important factor in the popularity of pipelines.

III. RESEARCH OPPORTUNITIES

Research work in oil transportation may be classified as both technological and logistical.

In the technological category, research in pipelines is pursuing the following: mechanics of liquid and two-phase flow, corrosion control including internal and external coatings, additives to reduce friction, increased strength of steel pipe, improved plastic pipe, improved welding techniques, mobile pipe mills, underwater pipeline construction, improved communication systems for automation, interface detector systems, mechanical separation of products, improved meters, and computer controlled pipelines.

In the marine field, research is dealing with simplification of design, internal and external coatings for corrosion control, cathodic type corrosion control, improved cargo handling (pumps, valves, gauging), improved offshore moorings, cryogenic transportation, improved propulsion machinery, improved navigation equipment, and automation, including centralized engine room controls.

In tank cars and trucks, the research is in improved materials to minimize weight and optimize strength within the limitations of railroad clearance restrictions, weight limits, and highway regulations; safety devices; faster loading and unloading.

Technological research in terminals continues in the realm of automating terminal controls, accounting and billing functions. In this latter category, equipment is visualized which permits the central office to control the release of products to specific accounts in predetermined amounts, keep terminal inventories, and issue invoices automatically as product is withdrawn.

Logistical research deals with means to optimize shipping territories of supply origins through mathematical techniques. If a particular refinery and its satellite terminals are short of supplies, it is usually less expensive to supplement supplies by shipping into the deficient territory according to certain patterns from refinery systems that have sufficient supplies than to move product by pipeline or marine transportation from one refinery to another. Then too, in a territory where over-all demand just equals supply, but supply is divided in fixed amounts among a number of origins, there is a particular pattern of shipment from origins to destinations which minimizes the total freight bill. This is the classic "transportation problem". While certain companies had developed various techniques to solve this problem "by hand", the method was generally laborious and time-consuming. In the last few years, however, due to research, the solution has been programmed on some of the larger computers and such freight optimization is now in use to a limited, but growing extent. Considerable emphasis now is placed on methods to feed automatically to the computers the statistics comprising account names, demands and freight rates. Logistical research is also progressing on methods to collect, summarize, and project supply and demand data in order to program operation of transportation equipment most efficiently.

IV. ECONOMIC OBJECTIVES

The aims of the oil industry's transportation effort have been and will remain primarily cost reduction, protection of product quality, and improved customer services. From the individual company's viewpoint, however, an even more basic aim has been economic survival. As profit margins in the industry have shrunk through competitive forces, the necessity to utilize advanced transportation facilities and techniques has increased. For example, Oklahoma refiners who originally shipped by tank car and subsequently built the Great Lakes Pipe Line to move products to more distant markets, have, in order to remain competitive, resorted to a number of additional product pipelines: Cherokee, Omar, Kaneb, Continental.

As to trends, the ultimate in efficient energy (petroleum) transportation would include a products line to the customer's oil tank or to the service station. While the connection to the homeowner's heating oil tank is foreseeable only in densely populated housing developments, there is likely to be pipeline delivery of oil to certain high-volume commercial and industrial complexes using oil for all energy needs: heat, refrigeration, electricity. Pipeline connections to service stations have not been installed on any large scale, but such have proved possible at certain high-volume stations which are located close to existing products lines or refineries. The chief development which is being realized and will continue into the future is the proliferation of products lines to serve truck-loading terminals in more and more communities across the country. Direct pipeline connections to industrial users and to airports (commercial and military) will be a by-product of this development.

No dramatic introduction of new type transportation is foreseen; but the already noted pressures of competition and the advantages of large-lot transportation and technological improvement are causing shifts between types of carrier and are revising the physical nature of the industry's transportation system.

Table 1
Page 1

PERCENT PETROLEUM IN
TOTAL U.S. ENERGY CONSUMPTION

	PERCENT
Coal	22.2
Oil	44.0*
Gas	29.8
Water Power	3.8
Atomic Power	0.2
TOTAL	100.0

*Includes natural gas liquids.

SOURCE: U.S. Bureau of Mines:
1963 extrapolated to 1965 by
Shell Oil Company

Table 1
Page 2

SOURCES: Shell Oil Company, Transportation and Supplies

Sun Oil Company, Economics Department, Analysis of World Tank Ship Fleet, December 31, 1963.

National Petroleum Council, Oil and Gas Transportation Facilities, 1962.

U. S. Bureau of Mines, U. S. and Puerto Rico Oil Improts, by Quarters for 1963.

American Petroleum Institute, Annual Statistical Bulletin, U. S. Petroleum Industry Statistics 1940-63, 1964.

U. S. Dept. of Commerce, United States Foreign Trade, U. S. Gov't. Printing Office, Feb. 18, 1964.

Corps of Engineers - U. S. Army, Transportation Lines on the Great Lakes System, 1964, Transportation Series 3, U. S. Gov't. Printing Office, 1964.

Corps of Engineers - U. S. Army, Transportation Lines on the Mississippi River System, Transportation Series 4, U. S. Gov't. Printing Office, 1963.

National Petroleum News, Fact Book Mid-May 1964.

U. S. Dept. of Commerce, Merchant Marine Data Sheet, November 1, 1964, U. S. Gov't. Printing Office.

Oil and Gas Journal, October 19, 1964.

Table 2

PETROLEUM TRANSPORTATION FACILITIES

FACILITY	# UNITS	VOLUMETRIC CAPACITY M DWT	VOLUMETRIC CAPACITY MM BBLS.	REPLACEMENT COST LESS DEPRECIATION TO DATE MM $
OCEAN TANKERS				
American Flag	440*	8,912	78.0	
Foreign Flag	233	5,872	51.5	
Supplying U. S.	673	14,784	129.5	1,800
INLAND AND COASTAL BARGES				
Self-Propelled	181		1.7	
Non Self-Propelled	2,494		27.0	
	2,675		28.7	150
PIPELINES - MILES				
Crude Trunk	70,000			
Crude Gathering	78,000			
Products	57,000			
	205,000			3,200
RAIL TANK CARS	131,622		29.5	350
TRUCKS				
Transport	58,448		8.3	
Local Delivery (Gasoline)	22,200		0.6	
(Heating Oils)	70,948		2.7	
	151,596		11.6	1,050
STORAGE AND TERMINALS				
Terminals and Depots	29,664		405.2	
LPG Refrig Storage	8		2.0	
LPG Underground Storage	139		101.9	
	29,811		509.1	1,000
GRAND TOTAL			708.4	7,550**

*As of 11/1/64, 95 ships were inactive, of which 70 were government-owned and 25 private.

**Cf. $5 billion and $6 billion original gross investment as estimated respectively in "Petroleum Transportation Handbook", Harold Sill Bell, Editor, McGraw Hill, 1963, and "The U.S. Petroleum Industry", Stanford Research Institute, 1964.

Table 3

MILLIONS SHORT TONS DELIVERED
TOTAL CRUDE AND PRODUCTS

	PIPELINES		WATER CARRIERS*		TRUCKS		RAIL		TOTAL
	MILLION TONS	% TOTAL	MILLION TONS	% TOTAL	MILLION TONS	% TOTAL	MILLION TONS	% TOTAL	MILLION TONS
1962	502	43.36**	330	28.46	298	25.69	29	2.49	1,159
1961	484	43.60	323	29.06	274	24.64	30	2.70	1,111
1960	469	43.01	318	29.22	270	24.83	32	2.94	1,089
1959	464	43.22	310	28.86	267	24.82	33	3.10	1,074
1958	433	42.57	298	29.36	252	24.78	34	3.29	1,020
1955	412	42.94	284	29.56	223	23.17	42	4.33	961
1950	284	38.82	253	34.57	146	19.93	49	6.68	732
1945	241	44.06	142	26.08	96	17.60	67	12.26	546
1940	154	39.79	149	38.78	22	5.67	61	15.76	386

*U.S. Flag only. If foreign flag deliveries to U.S. ports were added the breakdown would be as follows:

1962	502	40.07	424	33.84	298	23.78	29	2.31	1,253

**The recently constructed 36-inch Colonial products pipeline from the Gulf Coast to New York will increase pipeline and reduce water carrier deliveries by about 2 percent of total deliveries.

SOURCE: The Association of Oil Pipe Lines

Table 4

SIZE OF PETROLEUM TRANSPORTATION FACILITIES

FACILITY	CAPACITY CURRENT NORMAL	CAPACITY CURRENT MAXIMUM	CAPACITY 1945 NORMAL	CAPACITY 1945 MAXIMUM
OCEAN TANKERS (DWT)				
American Flag	25,000*	106,600	15,000	20,600
Foreign Flag Serving U.S.	58,800**	114,800	15,000	16,800
INLAND AND COASTAL BARGE TOWS (Bbls.)				
Inland	60,000	186,000	35,000	60,000
Coastal	20,000	73,000	10,000	25,000
PIPELINES (Diameter in Inches)				
Crude Trunk	10/26"	34"	8/10"	24"***
Crude Gathering	4/10"	12"	4/10"	12"
Products	8/20"	36"	8"	20"***
RAIL TANK CARS (Gallons)	10,000	33,000≠	8,000	12,000
TRUCK-TRAILERS (Gallons)	8,500	16,000	6,000	10,000
TANK TRUCKS (Gallons)				
Gasoline and Heating Oils	2,000	4,400	1,500	3,000

*5 ships totaling 189,000 DWT's were under contruction at end 1963. Only 57 ships of U.S. fleet of 440 ships exceed 30,000 DWT and 144 vessels are greater than 20,000 DWT's. Only 6 ships exceed 50,000 DWT and largest is 106,600 DWT.

**326 ships totaling 18,023,000 DWT's were under construction in Europe plus Japanese yards at end of 1963. Of world fleet of 3,279 ships, 1,365 exceed 20,000 DWT's and 853 exceed 30,000 DWT's. Largest ship (Japanese) is 130,200 DWT and the next two (Liberian) are 114,800 DWT's each.

***Trend toward large diameter pipelines began in 1942 with the War Emergency Big Inch (24") crude and Little Inch (20") products pipelines from the Gulf Coast to the East Coast. Prior to that date the largest oil lines were 12" diameter.

≠At least one 50,000 gallon car in restricted service.

SOURCES:
Shell Oil Company, Transportation and Supplies
Sun Oil Company, Economics Department, Analysis of World Tank Ship Fleet, December 31, 1963.
National Petroleum Council, Oil and Gas Transportation Facilities, 1962.
Corps of Engineers - U.S. Army, Transportation Lines on the Great Lakes System, 1964, Transportation Series 3, U. S. Government Printing Office, 1964.
Corps of Engineers - U.S. Army, Transportation Lines on the Mississippi River System, Transportation Series 4, U. S. Government Printing Office, 1963.
American Petroleum Institute, Petroleum Facts and Figures, 1963 Edition, p. 92 (using Interstate Commerce Commission and Bureau of Mines as sources).
Oil and Gas Journal, various issues and articles.

Table 5

FREIGHT SAVED BY LARGE-LOT CONCEPT

PIPELINE	LINE DIAMETER INCHES	¢/BBL. FOR 1,000 MILES		COST AS PERCENT OF SMALLEST UNIT		PERCENT SAVED VS. SMALLEST UNIT	
	10	51		100		-	
	14	36		71		29	
	18	27		53		47	
	24	21		41		59	
TANKER	SIZE SHIP-DWT	ESTIMATED $/LONG TON GULF-NEW YORK					
	16,000 T-2 (a)	4.20		100		-	
	25,000 (b)	3.02		72		28	
	47,000	1.97		47		53	
	67,000	1.81		43		57	
BARGE	SIZE TOW-BBLS.	¢/BBL. FOR 500 MILES					
	40,000	17.6		100		-	
	60,000	15.7		89		11	
	90,000	14.1		80		20	
TANK CAR	SIZE CAR-GALS.	¢/GAL. FOR 1,000 MILES					
	10,000	5.5		100		-	
	20,000	4.1		75		25	
TRUCK	SIZE TRUCK GALLONS	¢/GAL. FOR 50 MILES PRIVATE	FOR HIRE(c)				
	6,500	0.7	0.7	100	100	-	-
	8,500	0.5	0.6	71	86	29	14

(a) Ships of this size are no longer constructed for this service and are used for comparative purposes only. There are, however, many still in operation on which typical operating costs are closer to $3.20/long ton.

(b) Although $3.02 represents new construction, there are a great number of jumboized T-2's of this capacity which freight for closer to $2.50/long ton.

(c) Based on "Dedicated Service" common carrier.

SOURCE: Shell Oil Company
Transportation and Supplies

Table 6

EXAMPLE OF
EXTRA TERMINAL CAPITAL REQUIRED
TO SERVICE LARGE TANKERS VS. ORDINARY T-2'S;
ALSO MINIMUM THROUGHPUT NECESSARY
TO WARRANT LARGER TERMINAL

	TYPICAL PRODUCTS TERMINAL HANDLING 4 M-B/D				
	SIZED TO HANDLE 16 M DWT T-2 TANKER		SIZED TO HANDLE 37 M DWT TANKER		EXTRA COST OF 37 M DWT TANKER TERMINAL
	SIZE	M-$	SIZE	M-$	M-$
Land and Site Preparation	15 Ac.	165	20 Ac.	220	55
Tankage	260 MB	460	460 MB	805	345
Loading Rack, Office, Misc.	-	250	-	250	-
Dock	525'	1,000	650'	1,500	500
TOTAL		1,875		2,775	900
Inventory @ $3.50/Bbl.		910		1,610	700
GRAND TOTAL		2,785		4,385	1,600

Assume 37 M DWT ship saves 10¢/bbl. vs. older T-2:

Annual cost of 10% representing interest and amortization on $900 M extra cost of terminal	$90 M/Y
Interest alone at 5% on $700 M extra inventory	$35 M/Y
Total extra annual terminal cost	$125 M/Y

Throughput necessary for 15¢/bbl. saving of 37 M DWT Tanker vs. T-2 to offset extra annual cost of larger terminal = $\frac{\$125,000}{\$0.10}$ = 1,250 M-B/Y =

3,400 Bbls./Day

SOURCE: Shell Oil Company
Transportation and Supplies

Table 7

U. S. PORTS
DRAFT AND SIZE (DWT) OF TANKERS HANDLED
PRESENT AND PROPOSED

PORT	PRESENT: MAXIMUM DRAFT TO AT LEAST ONE BERTH	PRESENT: LARGEST TANKER (DWT)	PROPOSED: MAXIMUM DRAFT AFTER EXISTING PROJECT COMPLETED	PROPOSED: LARGEST TANKER (DWT) AFTER EXISTING PROJECT COMPLETED
Portland, Me.	39'	50,000	45' - 1968	85,000
Boston, Mass.	35'	36,000	38' - 1968	47,000
New York, N. Y.	38'	47,000	45' - 1967	85,000
Philadelphia, Pa.	39'	50,000	-	-
Baltimore, Md.	37'	42,000	40' - 1969	53,000
Norfolk, Va.	37'	42,000	-	-
Mobile, Ala.	36'	38,000	38' - 1965	47,000
Houston, Tex.	34'6"	34,000	38' - 1968	47,000
Los Angeles, Cal. (Incl. Long Beach)	46'	100,000	-	-
San Francisco, Cal.	36'	38,000	45' - 1965	85,000
Portland, Ore.	33'	26,000	38' - 1970	47,000

SOURCES: Annual Report Chief of Engineers
U.S. Seaports - Port Series, Corps of Engineers, 1963
American Merchant Marine Institute
Asiatic Petroleum Corporation

Table 8
Page 1

CONSTRUCTION OF LOCKS AND DAMS ON THE OHIO RIVER

OLD STRUCTURE			NEW STRUCTURE UNDER EXISTING PROJECT			
LOCK NAME (NO.)	SIZE (FT.)	OPEN TO NAVIGATION	LOCK NAME	NO. OF LOCKS	SIZE (FT.)	OPEN TO NAVIGATION
7, 8, 9	600 x 110 (All)	1914, 1911, 1914	New Cumberland	2	1,200 x 110 600 x 110	1961
27, 28, 29, 30	600 x 110	1922, 1915, 1916, 1923	Greenup	2	1,200 x 110 600 x 110	1962
35, 36, 37, 38, 39	600 x 110	1919, 1925, 1911, 1924, 1921	Markland	2	1,200 x 110 600 x 110	1963
41	600 x 110 360 x 56	1921	McAlpine	3	1,200 x 110 600 x 110 360 x 56	1963
31, 32, 33 34	600 x 110	1919, 1926, 1921, 1925	Capt. Anthony Meldahl	2	1,200 x 110 600 x 110	1964
10, 11	600 x 110	1915, 1911	Pike Island	2	1,200 x 110 600 x 110	1965
17, 18, 19, 20	600 x 110	1918, 1910, 1916, 1917	Belleville	2	1,200 x 110 600 x 110	1967
43, 44, 45	600 x 110	1921, 1925, 1927	Cannelton	2	1,200 x 110 600 x 110	1968
12, 13, 14	600 x 110	1916, 1911, 1917	Hannibal	2	1,200 x 110 600 x 110	Authorized - Construction not started
21, 22, 23	600 x 110	1919, 1918, 1921	Racine	2	1,200 x 110 600 x 110	Authorized - Construction not started
48, 49	600 x 110	1922, 1928	Uniontown	2	1,200 x 110	Authorized - Construction not started

CONSTRUCTION OF LOCKS AND DAMS ON THE OHIO RIVER
(CONT'D.)

OLD STRUCTURE			NEW STRUCTURE UNDER EXISTING PROJECT			
LOCK NAME (NO.)	SIZE (FT.)	OPEN TO NAVIGATION	LOCK NAME	NO. OF LOCKS	SIZE (FT.)	OPEN TO NAVIGATION
15, 16	600 x 110	1916, 1917	Willow Island	2	1,200 x 110 600 x 110	Under Study
46, 47	600 x 110	1928, 1928	Newburgh	2	1,200 x 110 600 x 110	Under Study
52, 53	600 x 110	1928, 1929	Mound City	2	1,200 x 110 600 x 110	Under Study
50, 51	600 x 110	1928, 1929	Dog Island	2	1,200 x 110 600 x 110	Tentatively Proposed

SOURCES: Annual Report - Chief of Engineers, U. S. Army - Civil Works Activities - 1960

Ohio River - General Plan for Replacement and Modernization of Existing Navigation Structures - U. S. Army Engineer Division, Cincinnati, Ohio - October 1961

Table 8
Page 2

Table 9

FEDERAL APPROPRIATIONS FOR NAVIGATION IMPROVEMENTS
TOTAL U. S.

	$ (MILLIONS)
1963	224
1962	204
1961	211
1960	209
1959	190
1958	141
1957	135
1956	88
1955	42
1954	25
1953	31
1952	47
1951	48
1950	60
	1,655

SOURCE: 1963 Annual Report - Chief of Engineers, U. S. Army - Civil Works Activities - Vol. I

Table 10

TODAY'S FREIGHT COSTS
USING TYPICAL EQUIPMENT
(¢/BBL.)

STATUTE MILES	TANKER 25,000 DWT* LOW	TANKER 25,000 DWT* HIGH	BARGE 60,000 BBL. TOW* LOW	BARGE 60,000 BBL. TOW* HIGH	PIPELINES LOW	PIPELINES HIGH	TANK CAR 10,000 GAL. LOW	TANK CAR 10,000 GAL. HIGH	FOR-HIRE TRUCK 8,500 GAL. LOW	FOR-HIRE TRUCK 8,500 GAL. HIGH
100	7.0	9.0	6.0	7.5	5.0	15.0	36.0	58.0	41.5	66.5
500	11.5	14.5	14.0	17.5	16.0	50.0	82.5	178.5	158.0	342.5
1,000	16.0	19.5	24.0	29.5	25.0	70.0	112.5	353.0	219.0	688.0
2,000	28.5	35.0	47.5	58.0			214.0	673.0		

Equivalent average mills per ton mile for 500 mile stage:

	TANKER	BARGE	PIPELINES	TANK CAR	FOR-HIRE TRUCK
500	2.0	2.5	4.0	20.0	35.0

*Gasoline basis; includes reasonable return on investment.

SOURCE: Shell Oil Company, Transportation and Supplies, supplemented by other data from ship owners; published tariffs of selected major crude and products pipelines; representative for-hire truck and tank car rates.

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THE ECONOMICS OF NATURAL GAS PRODUCTION, TRANSPORTATION, STORAGE, AND DISTRIBUTION

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INTRODUCTION

The economics of the natural gas industry are largely influenced by the demands of a highly seasonal market. In meeting the demands of this market, the industry must operate within the confines of governmental regulatory bodies.

The increasing importance of natural gas in the overall energy picture of the United States is depicted in Fig. 1. Gas has increased its share of the total energy market from 18.0 percent in 1950 to 29.7 percent in 1963.[1] At the present rate of growth, the projected market for natural gas will be 17,880 trillion B.t.u. in 1975.[1] The large-scale movement of natural gas from established supply sources to existing and developing consumer markets entails a variety of operations: the production, purification, transportation, storage, and distribution of natural gas. The economics of the industry are characterized by the major differences in the costs of production and utilization. These differences are not due solely to the operations cited above but also to other factors such as varying rate structures and field contracts.

GAS PRODUCTION

In consideration of the risks involved, the exploration, development, and production of a natural gas field requires a tremendous investment. The major costs in production are the land, the rights, and the drilling of a potential field. Although no fixed values can be set on the first two items because they vary, well drilling costs are tabulated and are well known. Unfortunately, every well drilled is not productive. Thus in 1962, of a total of 43,944 oil and gas wells drilled in the U.S., 16,684 or 38 percent were dry holes (Table 1). These statistics include development wells. The success of wildcat wells is much lower.

Average well depths are increasing and, consequently, the cost per foot drilled. The sixth (1962) joint survey of the cost of drilling and equipping wells in the United States undertaken by the American Petroleum Institute, the Independent Association of America, and the Mid-Continent Oil and Gas Association reveals the following:[10]

Table 1.-SUMMARY OF 1962 DRILLING

	Oil	Gas	Dry	Total
Wells drilled	21,402	5,858	16,684	43,944
Footage drilled (thousands)	86,494	31,432	75,631	193,557
Expenditures ($ million)	1,161	569	847	2,576
Avg. depth per well, ft.	4,041	5,366	4,533	4,405
Avg. cost per well, $	54,223	97,093	50,793	58,635
Avg. cost per ft., $	13.41	18.10	11.20	13.31

Thus we see that by virtue of being 30 percent deeper, the cost of gas wells is almost 80 percent higher than oil wells, since costs increase very steeply with increased depth. Gas well costs per foot drilled increased from $17.65 in 1961 to $18.10 in 1962.

The most commonly accepted indicator of field gas prices is the average wellhead price compiled yearly by the U.S. Bureau of Mines.[12] The average wellhead price of natural gas has increased significantly over the past decade to 15.5¢/MCF in 1962 (Fig. 2). However, it should be cautioned that while this tabulation is useful in indicating trends it should not be construed as a measure of field prices. The U.S. Bureau of Mines data do not take into account the time delay in long-term supply contracts nor do they differentiate between low-value markets (such as carbon black manufacture) and high-value markets (such as interstate transportation).[8] A truer barometer of current wellhead prices are specific gas purchase contracts.

Gas Purification

Gas from the wellhead contains impurities that may be detrimental to the transmission pipeline. In order to reduce corrosion problems and improve gas quality, the gas has to be purified. Some wellhead gases also contain valuable heavy hydrocarbons which are removed and sold for greater value than fuel oil or gas.

The purification of natural gas varies with the type of gas produced. It may involve the removal of objectionable compounds such as carbon dioxide, sulfur compounds, and water. Some gases have to be scrubbed for light-hydrocarbon removal. The costs of such purification operations vary with the type of natural gas and the operations performed. To meet pipeline specifications natural gas is dried primarily by chemical means, wherein a desiccant or a hygroscopic liquid is used to absorb the water. Sulfur compounds are removed by standard techniques such as those using monoethanolamine and diethylene glycol solutions, and activated carbon boxes.

The recovery of liquid products (gasoline and light ends) from natural gas usually results in a credit to the purification operation. However, it may be uneconomical to remove the condensables, in certain cases, because their relative value is greater than the cost of their removal. The costs associated with purification are a negligible part of the overall gas costs. Reported purification costs at 15 major companies range from $0.000248 to $0.0173/MCF.[13] Average purification costs for major pipeline transmission costs run from $0.002 to $0.003/MCF treated.

TRANSPORTATION

The importance of natural gas pipelines is exemplified by the fact that as of 1963 about 200,000 miles of pipelines, not including field gathering and distribution lines, were in use to meet the demand for natural gas. The growth of the industry can be seen by the twofold increase in pipeline mileage (Fig. 3) over the past 15 years.[1] In 1964 it was estimated that over 11 trillion cu.ft. of gas would be transported and sold by natural gas pipelines, representing a movement of about 232 million tons of gas.[2]

Natural gas pipelines, because of their classification as public utilities engaged in the interstate transportation of natural gas, have been under federal regulation for many years. The Natural Gas Act of 1938 and its subsequent amendments places responsibility for this regulation with the Federal Power Commission (FPC). Therefore, prior to the construction of a new pipeline or the expansion or extension of present facilities, a certificate of public convenience and necessity must be obtained from the FPC. These certificates are usually granted only after extensive hearings and investigation on the adequacy of gas reserves dedicated to the project, competency of design, availability of market, and financing ability.

As compared to oil or product pipelines which act as interstate carriers, natural gas pipelines generally are not classified as common carriers; they own and sell most of the gas which flows through their lines. The growing market for which service is to be provided requires that the designer allow for increased future demands. He may do this by a number of means, e.g., the use of a lower line pressure during the early years of the project, provision for added compression capacity, and the installation of larger than necessary pipe. Assuming that the market and sufficient reserves exist, the utility must design and estimate the cost of the new facilities prior to obtaining FPC certification.

Pipe Costs

Many factors must be considered in evaluating the design parameters for any given pipeline project. The basic goal of any evaluation must be to optimize the design with respect to cost and capacity. The most influential factor in the design and cost of a pipeline for any given capacity is the pipe. Estimates for complete pipeline projects indicate that the cost of the pipe, including installation, is usually between 70 and 90 percent of the overall project cost. The basic factor in determining the cost of a pipeline is the type of pipe used. The designer's aim is to use the least amount of steel for a maximum delivery capacity, with the highest possible pressure and lowest possible installation costs.

Current F.O.B. mill prices for pipe (early 1964) range from about $175/ton for Grade B pipe (35,000 p.s.i. yield strength) to about $200/ton for X-60 pipe (60,000 p.s.i. yield strength). The balance of the installed cost of the pipe is for the coating and wrapping of the pipe and the actual installation charges. A summary of the three cost factors mentioned for various size pipe is presented in Table 2.

Table 2.-PIPELINE CAPITAL COST ESTIMATES[9]

Pipe Size, in.	Wall Thickness, in.	Yield Stress, p.s.i.	Pipe Cost, \$/ton	Ton/ mile	Coating Materials, \$/mile	Installation, \$/ft.
4-1/2	0.188	35,000	208	22.6	310	2.40
8-5/8	0.219	35,000	179	51.8	585	2.95
12-3/4	0.250	46,000	190	88.2	863	3.50
16	0.250	52,000	210	110.9	1086	4.00
20	0.250	52,000	208	136.9	1340	4.60
26	0.312	52,000	200	208.6	1747	5.40
30	0.375	52,000	188	314.2	2007	5.90
36	0.438	52,000	193	438.2	2434	6.70
42	0.500	52,000	202	586.1	2840	7.50

The cost for various size transmission line projects reported to the FPC in fiscal 1964[9] are summarized in Fig. 4. The costs presented include the right-of-way, materials (pipe, coatings, etc.), labor, and miscellaneous charges. The high and low costs are also shown. Local conditions can cause as much as a threefold variation in the cost.

Compressor Stations

After the pipe and its associated costs, the expenditure due to compression of the gas is the second major component of transmission investment. The number of compressor stations that should be utilized on a pipeline are a function of the distance, pipeline operating pressure, and delivery required, as well as the economic restraints such as operating costs (fuel, labor, maintenance, and materials), and fixed or owning costs normally encountered (insurance, taxes, and return on investment). It may be advantageous to allow a large pressure-drop between stations, which will increase compression costs at each station but will reduce the number of stations.

The basic investment cost factors in the installation of a compressor station are the compressor, prime mover, land and improvements, the structures, and the miscellaneous equipment. The average cost per horsepower for nine new mainline compressor stations reported to the FPC in 1964 was \$380.[9] The total installed capacity was 60,000 h.p. The cost varied from \$169/h.p. for 10,500 h.p. in Louisiana to \$518/h.p. for 6000 h.p. in New Jersey. Table 3 lists the average cost/h.p. reported from 1959 through 1964 for new mainline stations and additions. Compressor stations vary somewhat with line size; Table 4 shows the estimated cost for compressor stations as a function of nominal pipe size. These costs include land, engineering, equipment, purchasing, and inspection.

Procurement of right-of-way is often a major problem and can considerably increase the cost of a pipeline project. The type of land, the population density in the area, and the number of road, water, and rail crossings affect the economic decisions of alternate routes. Right-of-way costs range from \$2000 to \$4000 per mile. In actual experience as reported to the FPC for 30- and 36-in. pipelines the cost/mile averaged \$3650. These costs reflect construction in both mountainous and relatively flat terrain.

Table 3.-COMPRESSOR STATION COSTS[9]

	New Mainline		New Additions	
Fiscal Year	Total Capacity, h.p.	Cost, $/h.p.	Total Capacity, h.p.	Cost, $/h.p.
1959	123,980	325	79,770	271
1960	242,850	208	396,115	233
1961	36,750	326	85,560	266
1962	109,080	340	101,840	251
1963	45,000	338	90,800	222
1964	60,000	380	100,200	233

Table 4.-COMPRESSOR STATION COSTS[9]

Nominal Pipe Size, in.	Fixed Station Cost, $	Variable Station Cost, $/installed h.p.
12	250,000	250
16	250,000	250
20	300,000	250
26	500,000	225
30	500,000	225
36	650,000	225
42	650,000	225

A pipeline must also have communications facilities, maintenance facilities, meter stations, and sales and regulator facilities at delivery points.

Pipeline Construction and Transmission Costs

A large new pipeline proposal presented to the FPC in 1963 was the 1545-mile Gulf-Pacific Pipeline Company system designed to transport gas from south of Houston, Texas to the Los Angeles area. The application and the figures supporting it effectively summarize pipeline construction costs. The estimated cost of the project is $314 million or about $203,200/mile.[11] The line would require 15 compressor stations costing approximately $51 million or about $273/h.p. The mainline system would use 36-in. X-60 pipe for the major portion and would cost over $209 million or an average of almost $150,000/mile. The project investment costs are summarized in Table 5.

Table 5.-GULF-PACIFIC PIPELINE CO. COST ESTIMATE[11]

	Unit Cost, $	Total Cost, $
Mainline (1397.8 miles)	149,849/mile	209,458,900
Gathering line (45.0 miles)	72,162/mile	3,247,300
California Laterals (102.4 miles)	108,476/mile	11,108,000
Sales Regulator Facilities		1,550,000
Compressor Stations, (15,000-188,000 h.p.)	273/h.p.	51,381,500
Miscellaneous		2,733,300
Total Direct Cost		279,479,000
Overhead, 3.86%		10,787,000
Interest During Construction, 3%		8,708,000
Contingencies, 5%		14,949,000
Total Project Cost	203,200/mile	313,923,000

The total operating cost of a pipeline is composed of the actual cost of operations, maintenance, general services, and fixed charges. The greatest contributor, excluding gas purchase cost, to the total cost is the fixed cost (Table 6).

Table 6.-AVERAGE 1962 U.S. GAS TRANSMISSION COST[13]
(Including Return)

	Cost, ¢/MCF
Purchase and Production	20.6
Operating Maintenance	2.7
General Services	1.4
Fixed Costs	11.5
Average Delivered Cost	36.2

The overall cost of transmission generally averages about 1.5¢/MCF for each 100 miles. The average operating costs, as reported to the FPC,[13] for the transmission facilities of 15 pipeline companies is 10.1¢/MCF of gas delivered.[13]

Since transportation is a major component of the cost of gas, the industry has directed continuing efforts in the area of transmission and pipeline research with a view to improved and more economical techniques. Examples of this are the development of high-strength steel and the entry of gas turbines as prime movers. In addition, the A.G.A. has sponsored research on line pipe properties, multiphase flow mechanics and transient flow systems which will permit the design of optimized and economical transmission systems.

STORAGE

Distributing companies faced with seasonal variations in daily sendout normally control the average cost of purchased gas by peak-shaving and the sales of interruptible gas. Interruptible gas is that which is sold with the understanding that in times of excessive demand it will be delivered to other customers. However, when a distributing company is unable to sell interruptible gas at satisfactory rates, it will store summer gas to meet future winter firm gas sales. Therefore, one of the important components that influence the final delivered gas cost is storage. These large volumes of gas can be most economically stored underground in depleted oil or gas reservoirs and in porous water-bearing formations, or aquifers. Any storage system must be close to the point of use but, unfortunately, underground geological formations suitable for this type of storage are not available in all parts of the United States. Depleted oil or gas reservoirs are confined to areas where favorable conditions for the formation of oil and gas deposits once existed – areas that can be developed with much less expense and effort than would be required for aquifers. Because of the high developmental costs, aquifer storage costs more than storage in depleted oil or gas fields.

Economics

Before an economic evaluation can be made of a potential underground storage, certain engineering considerations have to be met.

Most important of these are:

1. Site location relative to transmission lines and market
2. Reservoir size in relation to gas turnover
3. Structural integrity, porosity, and permeability
4. Rate of deliverability.

These considerations also have an economic significance on the cost of storage. Obviously, the location of a prospective underground storage site as near to transmission lines and markets as possible is vital for decreased expenditures. The size of the reservoir is dictated by the maximum seasonal demand which has to be met and also increased demand in the future. High porosity is conducive to storage of a larger volume of gas for a given structure. Good permeability is desirable since it permits the storage structure to receive gas readily on injection and deliver it at high withdrawal rates when needed. In addition, the legal and economic problems of site, cost of the land, and the cost of development and operation of the storage field are decisive factors. The volume of cushion gas which will remain in the reservoir for the life of the project and provide the pressure for the working gas withdrawal rates should not be excessive since this will represent a major investment. Normally, the working inventory averages 50 percent of total inventory. Fig. 5 shows the growth of underground storage pools and the ultimate reservoir capacity since 1950.[1] Although total reservoir capacity has increased an average of 10 percent over the past 8 years, the rate of growth has slowed to an increase of only 2.8 percent in the past year.

In Fig. 5 we see that by the end of 1963, 278 underground pools were being used by 72 companies in 23 states with an estimated ultimate storage capacity of 3.7 trillion cu.ft. In 1963, $106 million were spent in new facilities; an estimated $140 million was spent on new facilities in 1964.

Cost

Individual components of the storage cost vary with company and location. Thus, although storage plant fixed investment, including cushion gas, may average $0.98/MCF of working storage capacity, the actual reported costs vary from $0.34 to $2.05/MCF. An idea of the relative contributory factors can be obtained from Table 7.

Table 7.-VARIATION OF UNDERGROUND STORAGE COST[5]

	Average, $/MCF	Range, $/MCF
Storage Plant Investment	0.98	0.34 - 2.05
Cost of Storage Gas		
Fixed Charges, 15%	0.15	0.051 - 0.308
Operating and Maintenance Expense	0.031	0.016 - 0.115
Inventory Value of Gas Withdrawn	0.279	0.097 - 0.433
Total Gas Cost/MCF	0.460	

Although the estimated ultimate capacity of underground storage has increased, the increasing gas demand and lack of suitable underground storage locations have spurred the industry into investigating alternate means of storage for peakshaving.

One of the newly developed methods is the storage of gas as a liquid. Liquid natural gas can be stored at atmospheric pressure and -259^{o}F., where it has the advantage of containing 630 volumes of gas as 1 volume of liquid. At present, three methods of LNG storage are available to the gas industry:

1. Aboveground metal tanks
2. Cryogenic inground storage
3. Belowground prestressed-concrete tanks.

The storage of LNG at cryogenic temperatures involves special problems and materials; techniques have been developed which permit the storage container to withstand the extremely low temperatures. The costs of LNG storage vary with capacity as shown in Fig. 6 for aboveground metal tanks ($1.80/MCF for 1 million MCF) and in Fig. 7 for belowground prestressed-concrete containers ($1.50/MCF for 1 million MCF).[7] The prestressed-concrete tank storage technique was successfully demonstrated at IGT under sponsorship of the American Gas Association. Present efforts at IGT are directed towards the storage of large volumes of LNG in underground caverns. The acceptance of the LNG storage technique has resulted in construction of three major installations in recent months. Double-walled metal LNG storage tanks are being installed at Birmingham, Alabama and San Diego, California, and a cryogenic inground storage pit is being constructed at Hackensack, New Jersey. Once the gas has been delivered to the city gate, perhaps having been stored at some intermediate point, it must still be distributed to the individual customers.

DISTRIBUTION

In 1963, 434,000 miles of distribution piping was used to supply 35.5 million customers. The dominant economic factor in gas distribution is the character of the demand which varies with each of the four types of customer application:

1. Residential and small commercial – non-spaceheating
2. Residential – spaceheating
3. Small-volume commercial and industrial – spaceheating
4. Large-volume commercial and industrial

In addition to these classifications a distribution company may also sell gas to the interruptible customers. As public utilities gas distribution companies have an implicit contract with their firm customers to satisfy their demands at all times. Since a high percentage of firm customers use gas for spaceheating, such demand is very responsive to weather conditions.

This widely fluctuating demand precipitates a problem of supply that is felt all the way back to the producer. However, we will confine ourselves to its effects on the distribution company, felt most keenly by the northern utilities who experience the widest temperature variations. The southern gas companies have the same problem, but to a lesser extent. The structure of gas rates stresses the necessity to maintain high load factors. The cost of gas to most companies is computed from a two-part rate. The first part, the demand charge, or fixed cost, is payable monthly and is based on the maximum, daily contracted (with the pipeline) quantity; the second part, the commodity cost or variable cost, is the direct cost for each 1000 cu. ft. of gas purchased. Table 8 typifies the problem faced by some distribution companies in the Northeast. In this instance, the demand charge is \$65/MCF of daily capacity contracted and the commodity cost is \$0.31/ MCF of gas actually delivered.

Table 8.-PIPELINE GAS COST

Usage, days	Cost, \$/MCF
1	65.31
5	13.34
10	6.81
50	1.61
100	0.96
200	0.64
300	0.53
365	0.49

It is readily apparent that management will attempt to optimize the purchase pattern of gas. Many methods are used to obtain a higher load factor than would be obtained through exclusive pipeline purchase. Fig. 8 shows a hypothetical sendout curve for a northern utility. It can be seen that a large "valley" exists during the summer months. Many gas companies attempt to fill this valley by selling interruptible gas to industrial and/or commercial customers, or through the use of storage systems which was discussed previously. Among the other techniques for peakshaving are the use of propane-air mixtures, manufactured gases, and special purchases of peakload pipeline gas.

Design

The distribution system must be designed to meet instantaneous peaks, as well as daily and seasonal demands. Distribution systems are generally designed to be able to serve the maximum rate of gas demanded over a 15-30 minute period.

Distribution system pressure is the first design parameter that must be defined after the load is known. The system pressure directly influences the cost of a system because the major investment (80 percent)[8] of a gas distribution company is in its mains and services. (Services are the pipes from the street mains to the customer's meter.) Pipe costs are directly related to volume of gas delivered and operating pressure. Maximum design pressure for distribution systems rarely exceeds 60 p.s.i.g.; many companies operate their systems below 25 p.s.i.g.

Because of the high proportion of investment in mains and services and their direct effect on the distribution cost, it is imperative that new distribution system investments be optimized. Future loads for expanding communities must be accurately estimated to optimize costs. The cost of mains varies considerably across various sections of the country because of the great variability of labor costs and its large effect on installed main costs. Generally, the only predictable costs are those of the pipe itself. However, some general estimates have been made. For example, the cost of installing 1000 ft. of a 6-in. steel main in a suburban area was estimated as \$5150; the cost of installing a 50 ft., 1-in. service would be \$175.[3]

The cost of new distribution facilities also includes the cost of meters and pressure regulators, which account for about 14 percent of total distribution system investment. The cost varies from about \$45-\$50 for residential meters to almost \$5000 for the large-volume meters. The average investment for distribution facilities is about \$325/customer.[4]

The total costs for gas distribution include fixed charges on the distribution system investment, and the operating, maintenance, and customer accounts expenses. The fixed charges, averaging about \$42.60/yr. per customer exceed all other costs combined, which have an average total of about \$19/yr. per customer.[8] The implication of these costs is that the design and operation of mains and services is of paramount importance and must not be left to chance. The distribution expenses contribute 9.3 percent of the total operating costs in a distribution company. Table 9 details the other items of expense. Note that purchase and production of gas are by far the largest contributor, 77 percent, to the total operating expenses.

Table 9.-TOTAL DISTRIBUTION COMPANY OPERATING COSTS IN 1962[1]

	Cost Distribution, %
Purchase and Production	77.0
Transmission and Storage	5.5
Distribution and Customer Accounts	9.3
Sales, Administration, and General	8.2
	100.0

While the cost of gas purchases offer the largest target for cost reduction through improved storage and transportation methods, the other costs offer many opportunities through advances in technology and improved methods. Such efforts are being extended by the industry through industrywide research by the A.G.A. and through individual company efforts. Activities include development of new methods of leak detection and studies of nonwelding techniques of joining pipe at IGT, and studies in the use of plastic pipe at Battelle Memorial Institute. A number of projects are also being conducted at the A.G.A. laboratories in areas associated with domestic gas usage.

CONCLUSION

We have traced the route of our supply of gas from the wellhead to the consumer and discussed the problems and role that each step plays in the overall economics. Although consumer gas prices vary, an average for all classes of service showing the contribution of each step can be calculated:

Table 10.-AVERAGE GAS PRICE[1,13]

	Price Factor, ¢/MCF	Contribution, %
Production	20.4	32.4
Purification	0.2	0.3
Transmission	15.6	24.8
Storage	0.7	1.1
Distribution	26.0	41.4
	62.9	100.0

Storage and distribution account for 42.5 percent of the average consumer price for 1 MMBtu (1 MCF) of energy. Following is the average price paid in 1963 for 1 MCF of gas in each of the three major classes of service:

Table 11.-AVERAGE PRICE PAID FOR GAS IN 1963[1]

	$/MCF
Residential	0.99
Commercial	0.77
Industrial	0.34

The large price variation among the different types of service is due primarily to the volume purchased and the allocation of the entire system's fixed charges on investment. The residential, most commercial, and a few industrial consumers, pay for and receive a guarantee of continuous service. Payment for this guarantee comprises a major portion of the fixed investment. Despite rising prices at the wellhead and in the nation's overall economy, the continuing advances in research and development in the gas industry have provided the consumer with relatively stable gas prices and have greatly increased the market demand for gas.

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Economics of Electric Energy Delivery

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Gentlemen, it's a distinct pleasure to be asked to talk to you today on the transport and storage of electric energy. We've taken the liberty of calling our discussion the "Economics of Electric Energy Delivery," and you'll note soon that one of the hallmarks of this talk is its inability to stick to the subject.

It is plain from the program that the role of our paper is to take over the discussion of energy from the point where this energy has been converted to electricity, and to see it delivered onto the premises of the ultimate consumer. If, on the way, this energy can be stored for a few hours, we're supposed to discuss that too.

In its simplest form, then, the discussion would concentrate on what the electric utility engineer calls the "T and D" system -- meaning, of course, the transmission and distribution system. And since the popularity of pumped storage, at least in the U. S., has recently zoomed upward, we could then discuss pumped storage as the ultimate in techniques for "storing electric energy" enroute from the conventional generating station to the customer.

Unfortunately for simplicity, but fortunately for power system planners who make a living because the subject is not simple, it is extremely difficult to divorce the subject of the transmission and distribution of electric energy from the subject of its generation. The economics of all three are indelibly and irrevocably intertwined, although, surprisingly, the subject of distribution can stand on its own feet without the other two much easier than can generation or transmission.

Before we get confused prematurely, let's start by defining a few terms in the jargon, and from the viewpoint of the electric power system operator. Let's pick out just five: generation, transmission, distribution, storage and interconnection.

The term "generation" is probably self explanatory. It means the facilities to convert energy from stored or flowing water, or from fossil fuels, or from the atom, to electricity. Generally, generation is accomplished, for economic and technical reasons, at voltages of about ten to twenty-five kilovolts. We'll later see that this voltage range is about identical to the range of primary voltages in the distribution system, so that in some cases it is possible to feed power at generated voltages directly into the primary mains for distribution. In fact, in the early power systems, this was the general rule. But economics and the geographical separation between the typical power plant location and that of the load center now decree otherwise in the usual case. So we come to our next definition.

The term "transmission" conventionally means the facilities to move the electric energy from the generating plants to bulk receiving points, and from the bulk receiving points to local distributing points. The bulk receiving points generally are called "transmission substations," and the local distributing points "distribution substations," and both types are located with economic finesse throughout the system.

The transmission lines tying generating stations to bulk receiving stations are generally regarded as the transmission system. They usually operate at voltages of 115,000 volts and up to 345,000 volts at the present time in order to minimize transmission losses by holding down current flow, and in order to pack maximum energy transport capability into minimum right of way real estate.

The network of lines tying bulk substations to distribution substations is often called the "subtransmission" system, and they may operate at voltages from 230,000 volts down to around 20,000. Very large customers may be served from the subtransmission system. The distinction is made between "transmission" and "subtransmission" according to the role they play in the power system, and not by the voltage level, which varies from system to system.

The distribution system is fed from the distribution substations, and it may operate from 26,000 volts down to about 4,000 volts. The distribution system may be radial when the individual feeders are not connected together, and the loss of which results interruption for the customer supplied from the line, or they may form a network and be fed from several substations. Larger customers and the secondary systems are supplied directly from the distribution system.

When we talk about storage we do not mean storing energy in the form of electricity, as it cannot be done economically in large quantities. We also want to exclude here the economics of fuel storage. The only known economic way to store electric energy enroute from the conventional generating station to the customer is by pumped storage. This technique involves pumping water from a lower reservoir to a higher one during light load time at low production cost in order to release the water at the time of high demand and high production cost. Actually, another indirect form of storage is achieved by a conventional hydro station where the water is retained in the reservoir when the energy is not needed and released only when the demand is high.

Interconnections are simply transmission lines built between two or more neighboring utilities to interchange energy when it is mutually advantageous; that is, when one can produce excess power at a lower cost under normal conditions and for mutual help during emergencies. In case several systems join in an interconnection agreement the group is frequently called a power pool.

While each of these major parts of a power system has its own characteristic economic problems, the economics of the electric energy delivery must be looked at from the standpoint of the whole system. Specific problems, such as transmission and pumped storage, cannot be divorced from economics of operation and expansion of the entire system.

We will first briefly talk about the economics of producing power and expanding a system in general, then will go into detail of the economics of transmission.

Figure 1 shows the invested capital structure of a typical power company. Power plants take the largest share, but distribution facilities take almost as much. Transmission takes a smaller share and the "others" category includes items like buildings, shops, vehicles, etc. This relative distribution, of course, may vary from company to company depending on the location and density of load, but it is quite representative of the industry as a whole.

Economic Operation of a power system

A power system in existence, with the facilities then available for service, must be operated with maximum economy. Further, the system must be expanded in the most economic manner to meet future loads. These two problems are not really separable because, in planning the economic expansion of a system, the operating characteristics of the future system is very important. Setting down the operating principles is, therefore, logical and necessary to form the basis for further discussion of the problem.

Load Characteristics

Before we can talk about the operation of a system, it is necessary to discuss the unique load characteristics of a power system. Many basic economic problems are the direct result of these characteristics. Figure 2 shows typical daily load characteristics of a power system. The chart shows the load for a normal winter weekday.

The shape of the curve may change from season to season, as temperature and the daylight hours vary. Basically, the load has a minimum value below which the load never descends, sharply increasing periods and peak loads lasting only a few hours a day, followed by rapidly decreasing periods. The power generated by the system every moment must be equal to the demand, as energy cannot be stored economically in the form of electricity. The generating equipment available to meet the load usually varies in size, efficiency, reliability, and cost of fuel, etc., some located near load centers, some at far away hydro plants or minemouth generation sites. Spinning reserve must be available to cover the possibility of the sudden outage of some equipment and additional reserve capacity must be built to allow scheduled and non-scheduled maintenance.

To achieve minimum cost of energy delivery at all times, it is necessary to schedule the available generating units carefully throughout the day. The high efficiency units, which are characteristically the newer and larger size units and which characteristically burn the lowest cost fuels, are therefore utilized to provide as many kilowatt hours as possible and practicable. These units are assigned to carry the so-called "base load", and usually are not taken out of service except when maintenance is required. Less efficient units are assigned the next block of load and these may be taken out of service every night, except certain ones which may be kept on line for local area protection in case of transmission failure. Non base-load units are usually older units once themselves serving as base load units.

The peak load hours frequently are taken care of by so-called peaking units, which may be relatively low efficiency internal combustion units (diesel or gas turbine) or "bare bone" low efficiency steam units. Conventional hydro plants can be used for any of these purposes depending upon the characteristics of the available water and the storage. Usually the power system is interconnected to a neighboring system and can interchange energy to take advantage of the possible cost differences at any given period, or to provide mutual help in case of emergency.

At any given moment the total delivered energy has a definite cost value which depends upon the combination of cost values of all the generating facilities in service.

The transmission system makes it possible to operate all units in unison and naturally the loading on the transmission lines has some effect on the economics of of the delivery as the losses are higher, if the energy has to be delivered over long distances. The status of the transmission system may affect the whole system economy when uneconomical generation has to be kept in service during the outage of lines or frequently in anticipation of line outages in critical areas. Loading on the lines must be constantly monitored to prevent overloads even by deviating from the economic generation schedules.

The operation of the distribution system is largely independent of the generation system and its daily operation, as it is usually not affected by the loading schedules of the various generators with the exception of some small size peaking units, which may be connected directly to the distribution system. Operating arrangements and outages in the transmission and subtransmission system, however, may affect the distribution system.

Development of an economic power system

Having looked roughly at how an economical power system operates, let us now look into the future and see what basic economic factors govern its expansion. Again we must emphasize that the system as a whole must be considered to achieve the best results.

Let us assume that a reasonable load forecast is available for the entire future period under investigation, not only for the magnitude of the yearly peak load on the whole system, but also the geographic distribution of it, the shape of the load curve and the kilowatt hours to be provided. Variation in this load forecast may materially change the economic expansion pattern, especially as to timing.

The objective of the planning is to develop a schedule of additions to the generation and transmission facilities which assures that the projected load will be met with acceptable reliability and the cost of energy will be minimum in the future. Investment cost of the new equipment, generating and transmission, and the overall operating cost of the entire future system must be carefully analyzed.

Turning to generation expansion problems, there are usually a very large number of alternatives available. The location of new units as related to the existing and projected transmission system is one of the first considerations. The size of the unit has a strong influence on the installation cost, as the cost per kw decreases with the increase in size. The amount of necessary reserve capacity depends upon the size and reliability of the existing and future units. If only a few large size units are built it will be necessary to have more reserve capacity to cover the outage of the large units. This may be detrimental because the extra reserve capacity may cost more than the gain from the large units. The fuels to be used, especially the projected fuel prices at the considered location, may be decisive. The selection of types of units, for example base load versus peaking, is one of the most interesting tasks of a system planner. No universal rules can be set forth, as size of the particular system under consideration, the potential load growth, fuel prices, available hydro, etc., all play decisive influence. One may think, why not build only large efficient units in the future to take advantage of the decreasing installation cost. If we note that the load on the system is such that the peak demand lasts only for a short period, it is obvious that the large units will not be loaded up always to their maximum, and nearly the most efficient value, but will have to run often with 3/4 or 1/2 load with the corresponding loss of efficiency. One may go to the other extreme; install smaller size peaking units with relatively low efficiency but take advantage of the lower installation cost as both factors influence the ultimate cost of the delivered energy. It is very difficult, in fact dangerous, to use rules of thumb in this analysis. The industry has had to resort to the most modern analytical methods to get satisfactory results in the proper balance and timing of various types of generating units.

The location of the units is determined by the relative economics of fuel prices versus transmission cost and such important factors like availability of cooling water, air and water pollution restrictions, and government regulations and public acceptability in case of nuclear plants. Smaller size peaking units (diesel and gas turbine) may be located near load centers but the inherent noise problem can be prohibitive.

We haven't tried to analyze in detail all the factors involved in generation planning, but merely pointed to the most important ones to emphasize the complexity of the problem and the relations to transmission and storage.

Transmission and distribution planning

Transmission planning cannot be separated from generation planning and to a lesser degree even from distribution planning. The roles of transmission are: to carry large blocks of power from the generating stations to the load centers and provide interconnection with neighboring systems; to share reserve capacity and diversity; and to allow interchange of energy on an economic basis. The most economic solution is arrived at when these functions are integrated into one scheme and the individual lines fulfill more than one of these functions. If the problem were only bulk transportation of energy from point to point, other means may prove more economical as Figure 3 shows. These typical data, of course, include the fixed charges as well as operating costs and losses. The data for this chart was taken from a technical committee report of the FPC National Power Survey. Electric transmission is, however, the only means to move energy generated at remote hydroplants.

The capacity of a transmission line, using the same conductors increases proportionally with the voltage while the relative losses decrease. The first planning consideration is, therefore, the voltage to be used for a transmission project. Naturally, at a lower voltage more circuits are needed to carry the same power flow and considering the limitations of right-of-ways and the need to transmit larger and larger amounts of power in the future, it is easy to see why transmission voltages go upward by leaps and bounds to limit the number of circuits and thus the right of way real estate needed.

Figure 4 shows the historical development of highest transmission voltages used in this country. Except for a few experimental lines, at the present time the highest transmission voltage in this country is 345, 000 V, but shortly many 500, 000 V lines will be operating. 700, 000 V transmission will follow in a few years with a large Canadian hydro project. Previously there was not great pressure in this country to raise transmission voltages as most load centers had ample fuel supply nearby. In the meantime, the technology of EHV developed sufficiently and the utilities began to realize that to keep ahead of the increasing demand and keep rates down they have to build larger more efficient units at locations where fuel prices are low. Individual systems are sometimes too small to take full advantage of these developments.

Therefore they have combined their effort to build commonly owned plants and interconnect with neighboring systems and pools by EHV lines.

Another factor plays a significant role for the private utilities; that is competition or potential competition from publicly-owned power suppliers. Sometimes the economic analysis shows no clear-cut advantage for a scheme incorporating extensive EHV. In borderline cases intangibles, such as these competitive considerations, may decide in favor of EHV.

It is obvious that as we increase the voltages of the transmission system we can transmit more power on the right of way and generally we need less number of lines to transmit the same amount of power. Although the outage rate of the higher voltage lines generally is less than the lower voltage lines, the planner has to assume that they would fail occasionally. Therefore, at this point we have to introduce the concept of firm supply. Let us assume, for example, a remote mine mouth plant which for its very nature will be used as base load generation. A single line between this mine mouth plant and the load center obviously cannot be considered firm because even the highest degree of preventive maintenance cannot assure it. To firm up the transmission scheme a second line should be built. The capacity of each line should be at least as much as to be able to carry the full output of the plant during the outage of one of the lines. Therefore, normally the lines will be utilized only partially. Under these conditions too high voltage level with the inherent higher expenditure may be uneconomical at least for the initial operation of the system. Expected later developments such as more generating units at the same location or along the line, or possible interconnections, may justify however the initial higher expenditure to forestall future even higher expenditure. The economic planning of transmission systems is not a series of one shot affairs, but usually involves a coordinated study of as many as 25 to 30 years of developments. The economic solution is what results in the least expensive scheme over the whole period.

Figures 5, 6 and 7 show the cost of point to point transmission of 500 mw at 345 kv, 1000 mw at 500 kv and 2000 mw at 700 kv respectively. Each chart shows three curves reflecting the decrease of transmission cost as the load factor (L. F.), that is the utilization of the line, increased from 50% to 70% and to 85%. These curves were also taken from a technical committee report of the FPC National Power Survey. I would like to emphasize here that these illustrations represent typical values and may not be applicable to a particular situation, where conditions are different from what it was assumed in the FPC survey.

In congested areas the unavailability of rights-of-way, or local opposition, often prevents building overhead lines. Utilities frequently are forced to put the lines underground, which, of course, besides the technical and operating difficulties, involves substantially higher expenditures per circuit mile than overhead lines.

Hitherto we have talked about AC transmission only, but as you probably heard from recent announcements on the west coast two DC-EHV lines will be built together with several AC-EHV lines to bring the surplus hydro energy available in the Pacific Northwest to load centers in the Southwest. These lines will be built partly by private and partly by government agencies and it signifies an unusual cooperation between these two sectors of the electric utility industry in this country. Before we discuss the economics of DC lines versus AC lines, it may be worth pointing out certain important technical differences between them.

First, an AC line by its very nature fits into an existing system without too much difficulty. The power flow on an AC line is inherently determined by the difference of the balance of generation and load at each end of the line, and the equipment and operating methods are well developed. The DC line is an entirely different thing. The energy will continue to be generated and utilized at AC, therefore the power must be rectified to DC at the sending end and converted back to AC at the receiving end of the line. The rectifiers and converters are very expensive equipment especially when we talk about thousands of megawatts and voltages up to 1,000,000 V. The more expensive terminal equipment fortunately is compensated for somewhat by less expensive line design. The losses in a DC transmission line are less than on an AC line because it doesn't have to carry reactive power inherent in the case of an AC line. Operating methods, however, will be more rigid with the DC line involving more intricate control equipment for the whole system. Ignoring special cases, such as underground or underwater cable systems too expensive with AC, or connecting systems with different frequency, DC lines can compete successfully with AC lines only in point to point long distance transmission of very large amounts of power. This restriction of the DC application stems from the relative cost of the terminal equipment and the inflexibility of the DC transmission as far as the future extension of the system is concerned. If along the proposed transmission route important load centers are expected to develop or new generating units will be built, the AC line offers a distinct advantage because it can be more easily tapped according to the requirement. The place of DC lines, at least at the moment, is in clear-cut long distance point to point transmission, or in the special cases of underground or underwater transmission mentioned.

Figures 8 and 9 compare the cost of point to point transmission by AC versus DC for a "typical" case. The cost figures include the cost of the terminal facilities too.

Distribution

We pointed out earlier that the economics of the distribution can stand on its own feet, largely independent of the economic considerations in associated generation and transmission. Distribution systems are as varied as the areas they supply. A distribution system in a rural area has different problems than a densely populated urban area. It is of course more economical to locate the distribution substation somewhere near the center of the area it serves, but frequently it is not possible and the utility has to consider alternative locations. It is increasingly difficult to acquire property in densely populated areas because of zoning problems or because property is simply not available.

The location of the substations is one of the most important economic factors in the distribution system as it determines the length of the feeders from the station to the customer. Just like in the case of generation and transmission it is not sufficient to solve the immediate problem, but the future load growth has to be taken into consideration. Later, more and more substations will be needed and the system should be so designed as to make it easy to affect future extensions and changes. Sometimes substation property must be acquired well in advance of the actual need to assure its availability.

The quality of electric service is measured by its reliability, and by tightness of voltage and frequency regulations at the point of delivery. Except for frequency, most troubles originate in the distribution system. It is more vulnerable to adverse outside influences, such as weather, than the transmission system.

Rapidly increasing customer loads coupled with the previously mentioned factors has resulted in an upward push in distribution voltages. Recently utilities have decided to build underground systems to improve the appearance of the community and at the same time the reliability of service. These tendencies naturally resulted in increased cost of the distribution system. An underground distribution system still costs much more than an equivalent overhead system. The utilities are making a great effort to keep this cost down by constantly improving the methods and equipment.

Pumped storage

We have been asked to talk about storing energy and, as mentioned before, it cannot be stored economically in the form of electricity. Early in this presentation when we discussed the operation of a system we pointed out that the cost of total energy at any given moment depends upon the generating units providing it. As the load increases on a system at a given day, more and more units are put into service with lower efficiency and higher operating cost. If we can devise some means whereby we can store energy produced at a low cost and release it at a time of high demand and high cost, we may justify the expenditure for that storage.

The operation of a pumped storage plant is simply to pump water from a lower reservoir to a higher one during light load periods on the power system when only efficient units operate, usually at night and weekends, and release the water to generate energy during heavy demand when otherwise inefficient units would have to be operated.

Pumped storage plants, utilizing this concept, have gained popularity in this country. The concept was known for many years but in this country it had not been popular until the economic reversible pump-turbine was developed some years ago, which made it possible to lower installation costs. Before, each unit consisted of a generator-motor and a separate pump and turbine, all on the same shaft.

Naturally, the pumping-generating cycle involves losses and at the present such plants operate at about 66% cycle efficiency; that is, only 2/3 of the energy used to pump the water to the upper reservoir can be regained when generating. What makes then such a plant economic for a utility? We have to look again at the daily load characteristics of a system and the available generating units to meet the load most economically. We have talked about it briefly, but to understand the economics of pumped storage we have to look into the subject in more detail.

The generating system consists of many units, some of them large efficient base load units, some older less efficient units, once themselves base load units, which are normally shut down during light load periods, and peaking units used only during the heaviest demand period. The relative balance of these units varies with each system. If the system has a relatively high proportion of efficient units, these may have to be curtailed during light load periods with the resulting loss of efficiency. It may even be necessary to shut down some of them frequently, thus incurring extra cost for start-ups and subjecting them to incremental maintenance. With such a system, the pumped-storage should be investigated as a means to provide peaking capacity provided, of course, that a suitably economical site is available for such a development at a reasonable distance. The operation of the system then would be that during light load the efficient steam units, which otherwise would be partly loaded or shut down, would provide the pumping energy at a relatively low cost, thus filling the valleys of the load curve. During heavy demand the pumped storage plant would provide the peaking energy at a lower cost than alternative peaking units could. Figure 10 shows the daily load curve of a system with pumped storage. As you can see the base load units are fully loaded throughout the day. When the actual load drops below the capacity of the base load units during the night, the difference is used for pumping. During peak hours the pumped storage plant generates instead of other more expensive types of peaking units.

For example, let us assume that the base load units provide the pumping energy at 2 mills per kwh, then the cost of energy generated at the pump-storage plant will be 3 mills per kwh because of the losses in the cycle. This 3 mills per kwh figure then should be compared with the energy cost of other types of peaking to determine which one is more economical.

The installation cost of the pumped storage plant and the alternative peaking plants, and the operating cost of the whole system with and without the pumped storage must be very carefully analyzed to determine the economic solution. In this case just as any other problem, not only the present condition should be looked into but also how it affects future economies. The investigation also involves the analysis of the optimum size of the reservoirs at the pumped storage plant.

Naturally, the installation cost and the optimum size of the reservoir are largely determined by the local topographical and geological conditions at the site, which is beyond the control of the utility.

The geographical location of the prospective pumped storage plant, as related to load centers and generating stations providing the pumping energy is another important factor. The transmission lines leading to the pumped storage plant have to connect the plant with load centers and transmit pumping power from other generating sources. The problems are, therefore, somewhat more complex than with conventional hydro or steam stations and require detailed investigation and in the final analysis it may be decisive for or against the pumped storage plant. Several other factors can influence the economics of a pumped storage plant besides those just mentioned; such as the sharpness of the peak load period, that is its magnitude and duration, and the amount of excess cheap energy available for pumping during off peak periods. Obviously a system with sharp peaks will find a pumped storage plant more attractive than another system with flat peak periods and relatively cheap peaking energy already available from conventional hydro plants.

Expected future developments

We have discussed a few of the current problems of storing and transmitting electric energy. Now, based on the present conditions and trends, we can make a reasonable projection into the future.

The electric utility industry is facing a tremendous task. The load has been increasing at such a rate that it doubles every ten years. We can foresee no saturation in this respect and plans are based on the assumption that this trend will continue in the foreseeable future. This pressure of increasing load will inevitably force utilities to combine the efforts and form more interconnections and power pools. These pools in turn will make it possible to build larger and larger units. Individual systems of moderate size cannot hope to build these units, because of the penalty they have to suffer as a result, in the form of increased reserve requirement. But as a member of a larger group they can enjoy the full benefits, as the installation cost per kw decreases with the size. The overall reserve requirements will be less and operating costs are expected to decrease also. Naturally, these large size units will be built where fuel prices are advantageous. As gas and oil prices are increasing there is a revival in the interest of coal in areas where coal has not been used, for example in the Southwestern part of the country. Elsewhere in the country, the coal transportation costs are decreasing, which has an important influence on this revival of coal. This development and the EHV transmission makes it possible for the industry to maintain a healthy economic status and at the same time decrease energy cost and provide more reliable service.

In the field of transmission we expect the voltages to go up to 1,000,000 V, which is technically feasible even today. Beyond this it is difficult to make predictions.

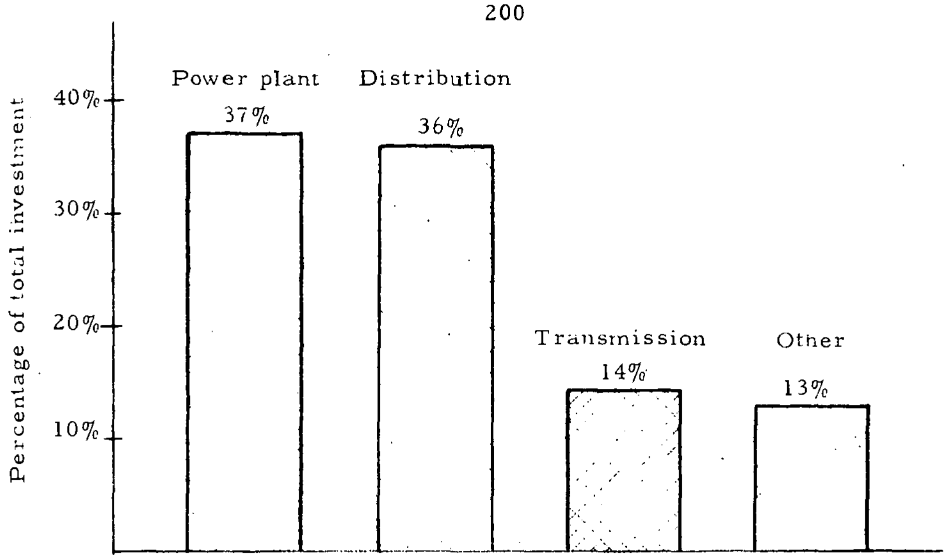
The relative share of hydro energy is going to decrease as economic sites are being rapidly developed in this country. There are huge hydro resources available in Canada however. In spite of this, it is expected that such regions as the Northwest, which hitherto has relied exclusively upon hydro power, will have to resort to other sources for energy in the not too distant future.

The relative share of nuclear energy in the future is still being debated. There is a general agreement that it can compete in areas of high fuel cost but recent announcements (Oyster Creek) indicate that it has a chance to compete in relatively low fuel cost areas, such as the Midatlantic states. Unquestionably nuclear energy will be used more and more.

We heard a lot of talk about various methods of direct conversion recently. All of these projects are in experimental stages and it is difficult to estimate their future influence. Only the MHD method appears to be economical in large size central stations at this time. Significant development, either economical or technological, can materially change the economic picture of future energy delivery.

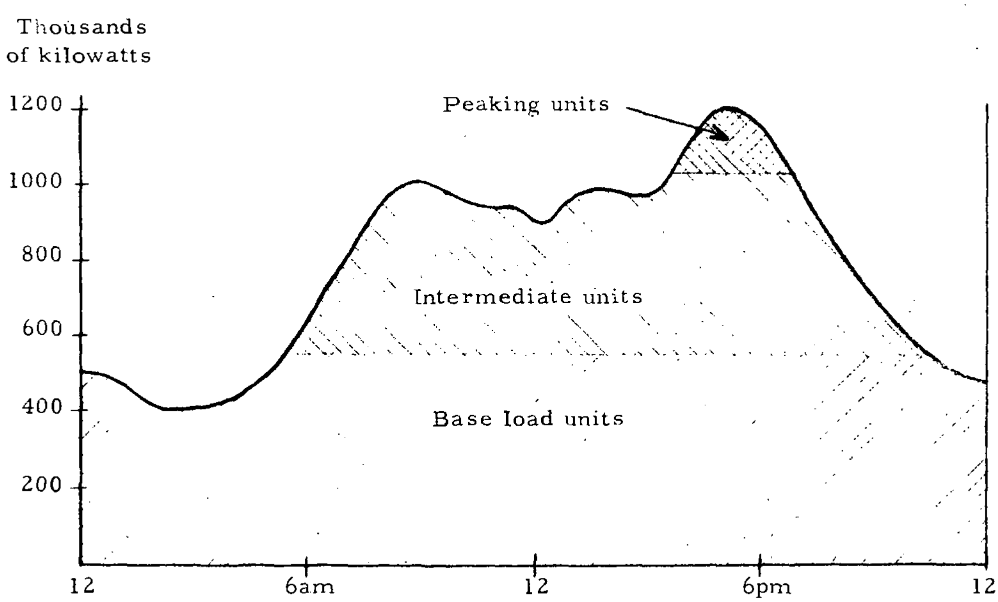
The electric utility industry, contrary to the popular belief, is not without vigorous competition with other types of fuels. They are vigorously campaigning to increase their load and one of the brightest areas in their competitive picture appears to be electric space heating. Their approach of promoting load growth and thereby decreasing the cost of supply, assures that electricity will continue its strong technological and economic development well into the future.

The speaker wishes to express appreciation to Mr. Zoltan Csukonyi of the Bechtel Corporation for his invaluable work in the preparation of this paper.



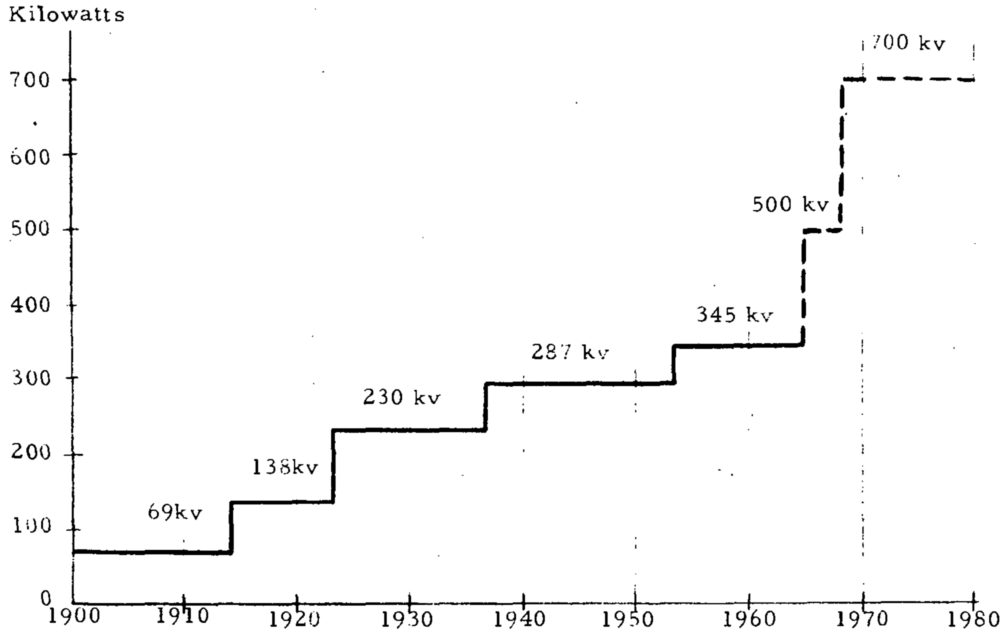
INVESTED CAPITAL STRUCTURE OF AN ELECTRIC UTILITY

FIGURE 1

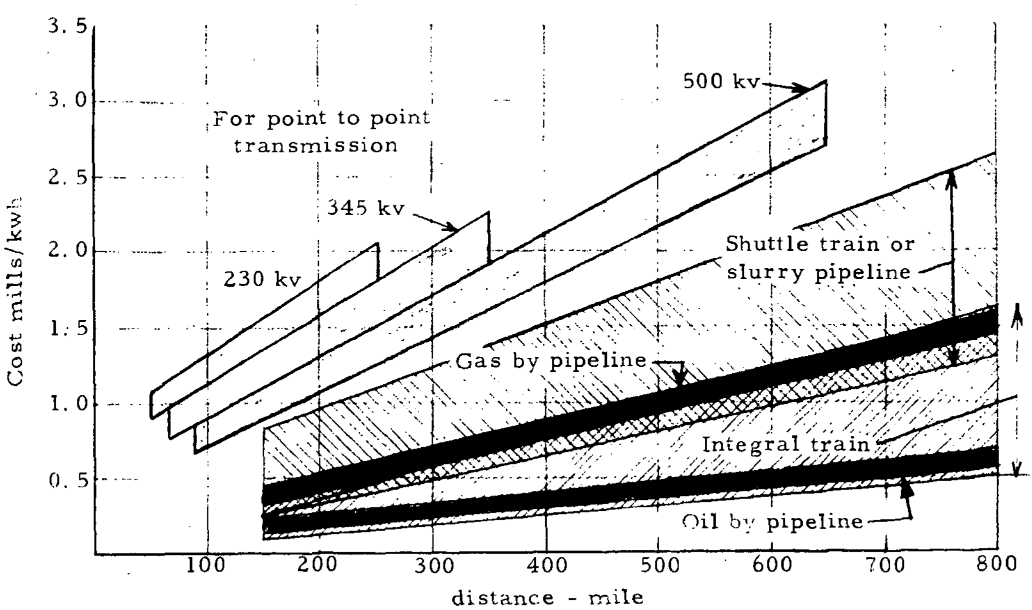


TYPICAL DAILY LOAD CURVE OF AN ELECTRIC SYSTEM (Winter Day)

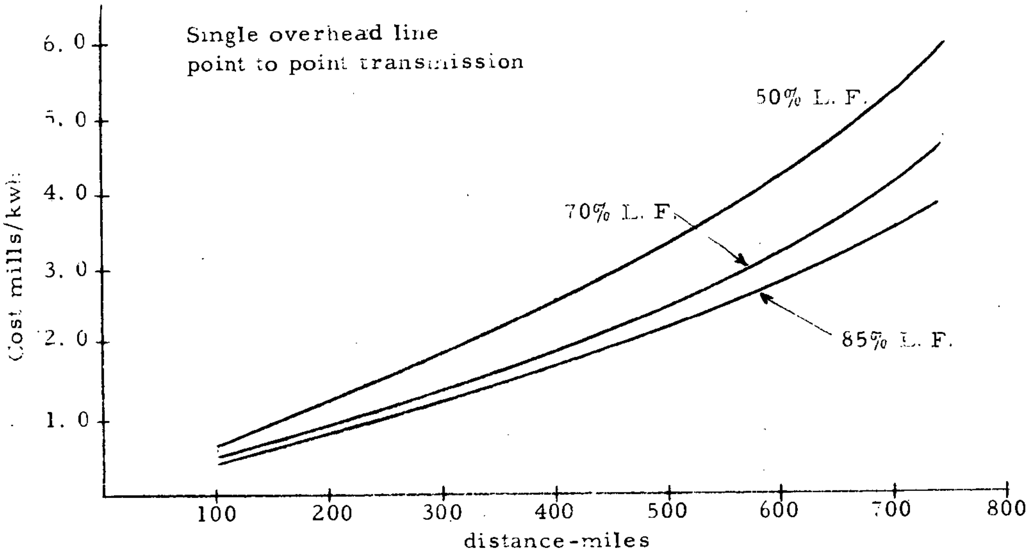
FIGURE 2



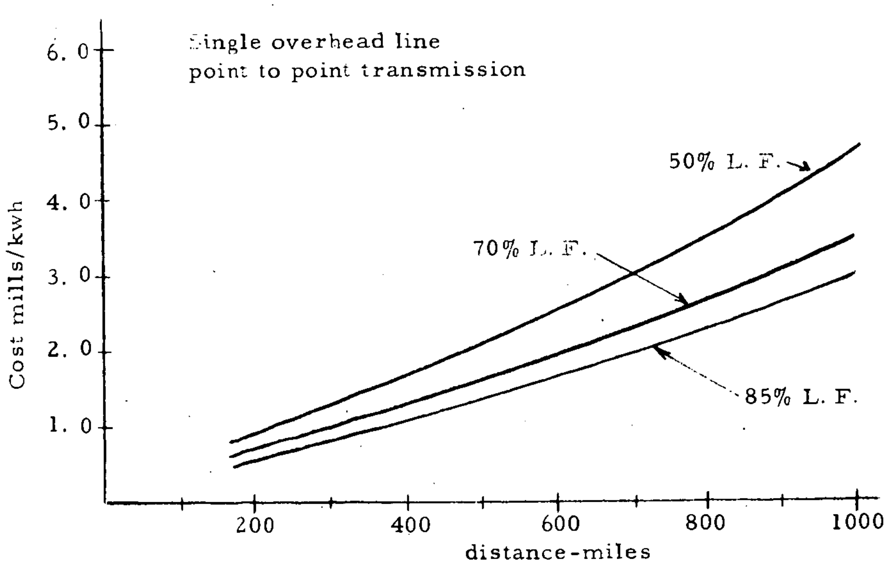
HISTORY OF HIGH VOLTAGE TRANSMISSION FIGURE 4



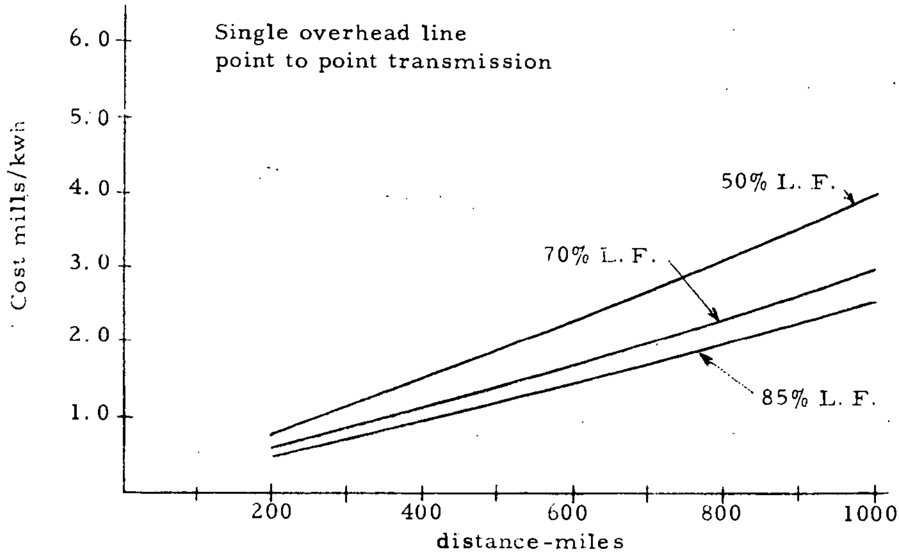
TYPICAL POINT TO POINT
ENERGY TRANSPORTATION COSTS FIGURE 3



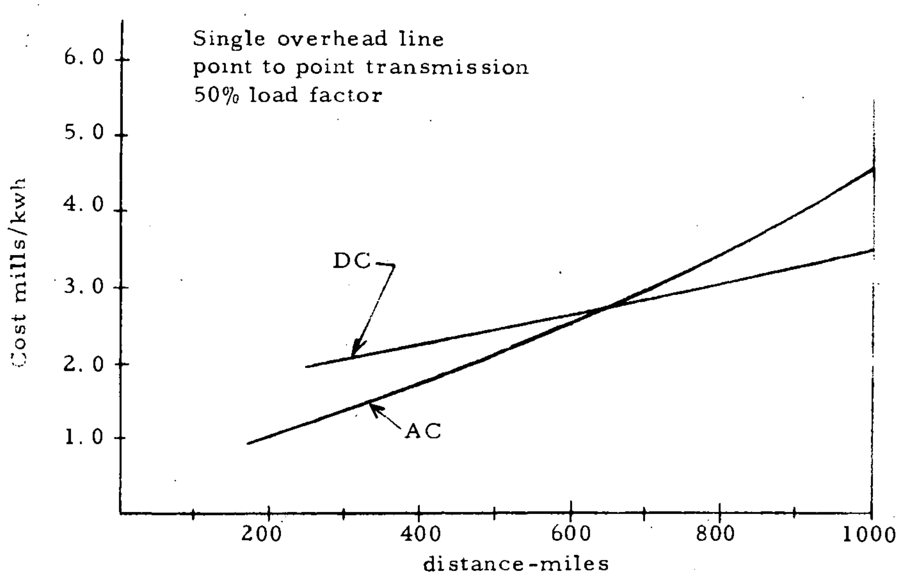
TYPICAL TRANSMISSION COST 345 KV-AC 500 MW FIGURE 5



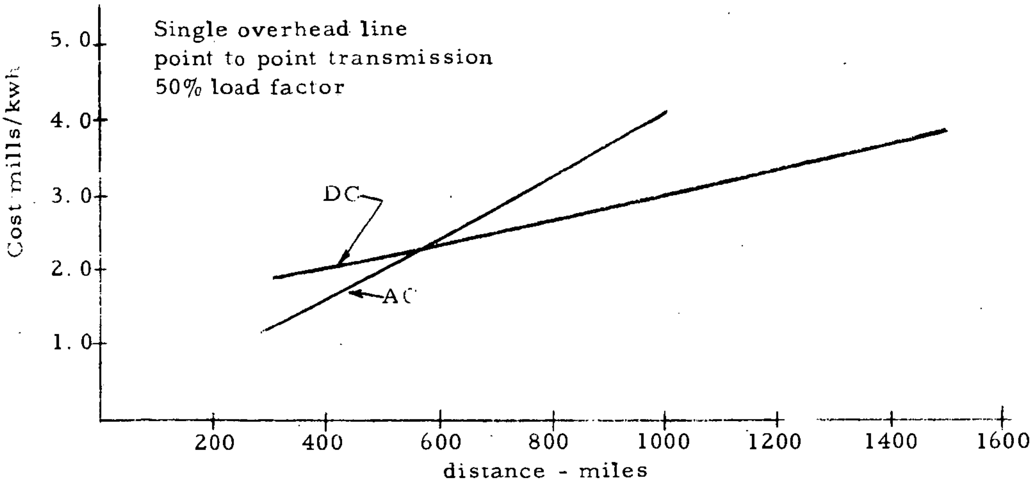
TYPICAL TRANSMISSION COST 500 KV-AC 1000 MW FIGURE 6



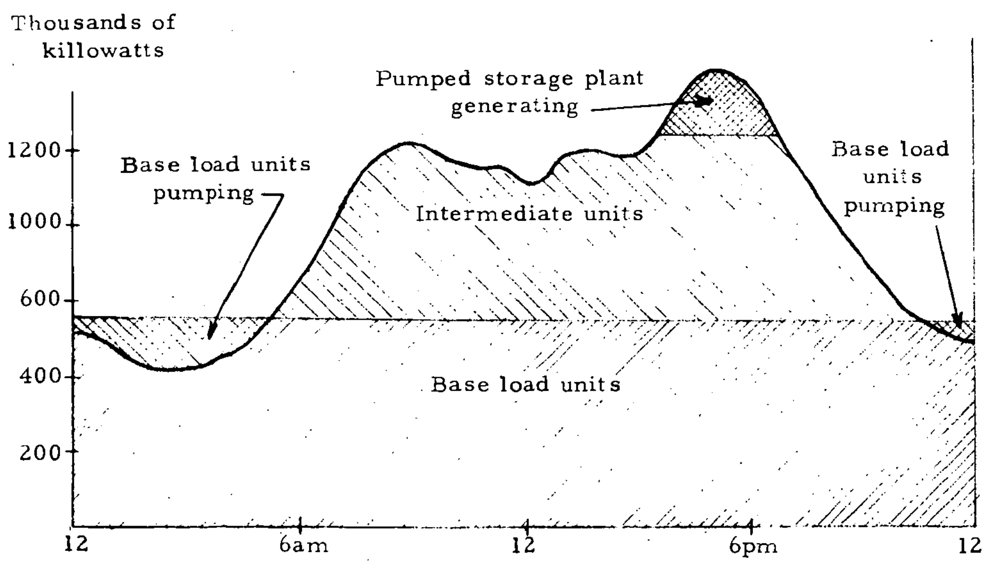
TYPICAL TRANSMISSION COST 700 KV-AC 2000 MW FIGURE 7



TYPICAL AC & DC TRANSMISSION COST COMPARISON
500 KV-AC vs ± 375 KV-DC 1000 MW FIGURE 8



TYPICAL AC & DC TRANSMISSION COST COMPARISON
700 KV AC vs $\pm$ 500 KV DC 2000 MW FIGURE 9



DAILY LOAD CURVE OF AN ELECTRIC SYSTEM
WITH PUMPED STORAGE FIGURE 10

PATTERN OF ENERGY CONSUMPTION IN THE UNITED STATES

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The pattern of flows of energy through the economy of the United States is an ever changing one. Major shifts in sources of energy and in the uses to which energy is put have occurred since the beginning of our industrial economy. This paper is limited to an examination of the post-war period. Within this decade and a half (1947-1962) there were factors which created a very different set of energy flows for 1962 from that of 1947. These changes will be examined, hypotheses concerning them will be presented, and projections to 1980 of the pattern will be made. Such an analysis should serve as a useful frame of reference for papers dealing with specific energy sources.

Two views of the energy economy are presented in tables. The first shows total energy resource consumption by consuming sector by source. The second shows energy resource consumption by consuming sector by function. Projections to 1980 are given for each view. The concluding portion of this paper presents a tentative hypothesis concerning competition among energy sources and energy trends.

Energy Consumption by Supplying and Consuming Sector

Tables 1 through 4 present energy balances by supplying and consuming sectors for selected years. Tables are presented for 1947, 1955, 1962, and 1980. Historical data are available for selected years covering the entire period 1947-1962 1/ but the trends are relatively smooth and a good picture can be obtained by examining the years I have chosen to include in this report.

Major shifts in energy consumption by fuel source have occurred between 1947 and 1962 (see Figure 1). Bituminous coal and lignite, which supplied 44 percent of the energy in 1947, dropped to 21 percent by 1962. Anthracite showed an even greater relative drop, declining from 4 percent to less than 1 percent. The decline of coal as a source was offset by increases in use of petroleum and natural gas. These shifts are clearly reflected in the pattern of growth rates by sources over this period. Total energy consumption increased at an annual rate of growth of 2.5 percent over the period. Bituminous coal and lignite showed an average rate of decline of the same amount, 2.5 percent. Anthracite declined at an annual rate of 7.5 percent. Hydropower increased at a 2-percent rate. The most rapidly growing sector was natural gas, showing an annual growth rate of 8 percent, while petroleum showed an annual growth rate of 4.25 percent.

The shifts between the relative size of the consuming sectors was also marked (see Figure 2). When electricity is not distributed to the other three consuming sectors (compare table 1 with table 3), the industrial and transportation sectors declined in relative importance while households increased slightly, but the major gain was recorded by electric generation. When electricity is allocated back to the other three consuming sectors, the picture changes a little. The household and commercial sector now shows a 7-point increase in its relative size, with both industrial and transportation declining (see tables 7 and 13).

1/ Morrison, W. E. Summary Energy Balances for the United States--Selected Years 1947-1962. United States Department of the Interior, Bureau of Mines, Information Circular 8242.

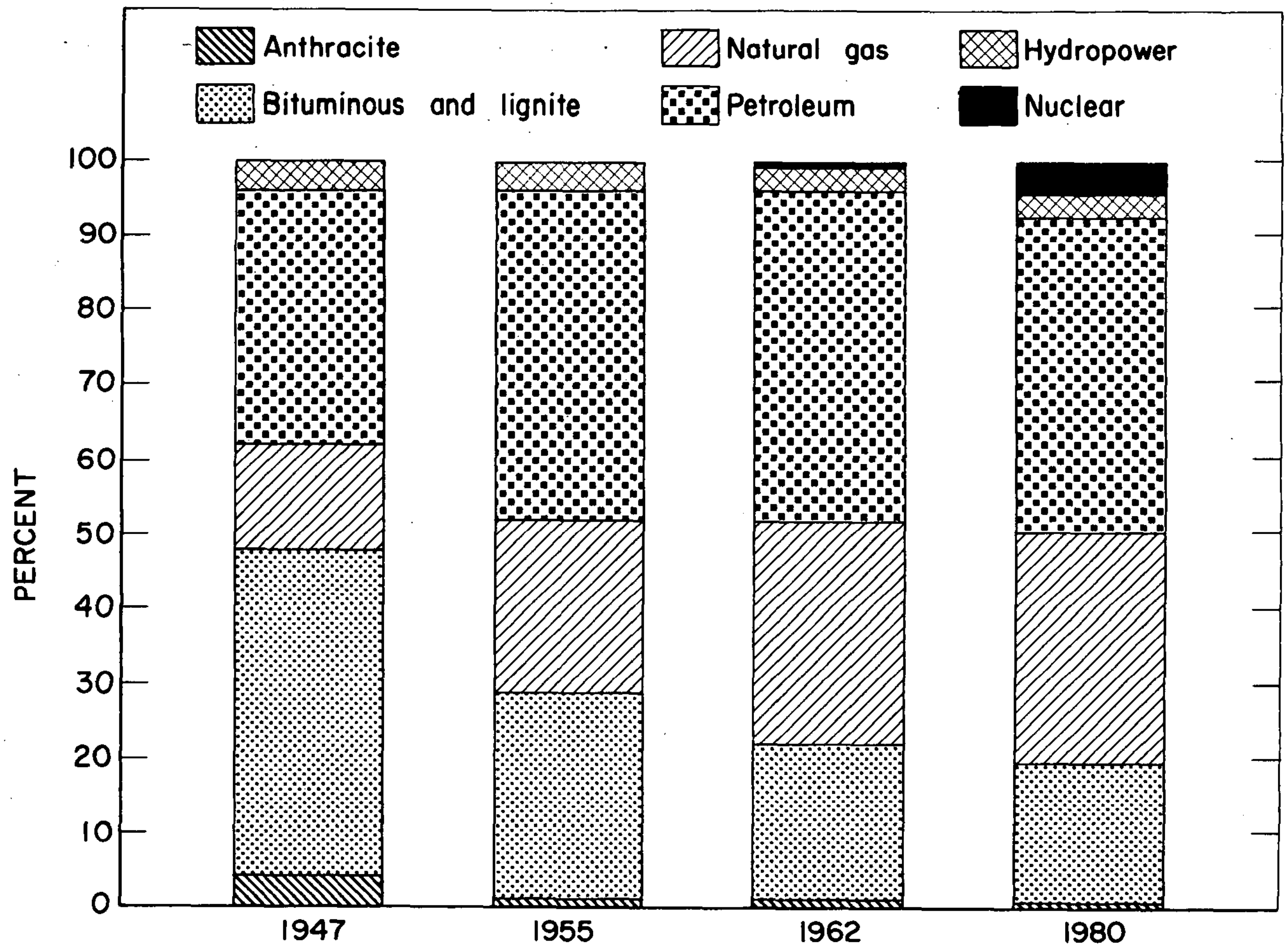

Figure 1.- United States Total Gross Consumption of Energy by Major Sources.

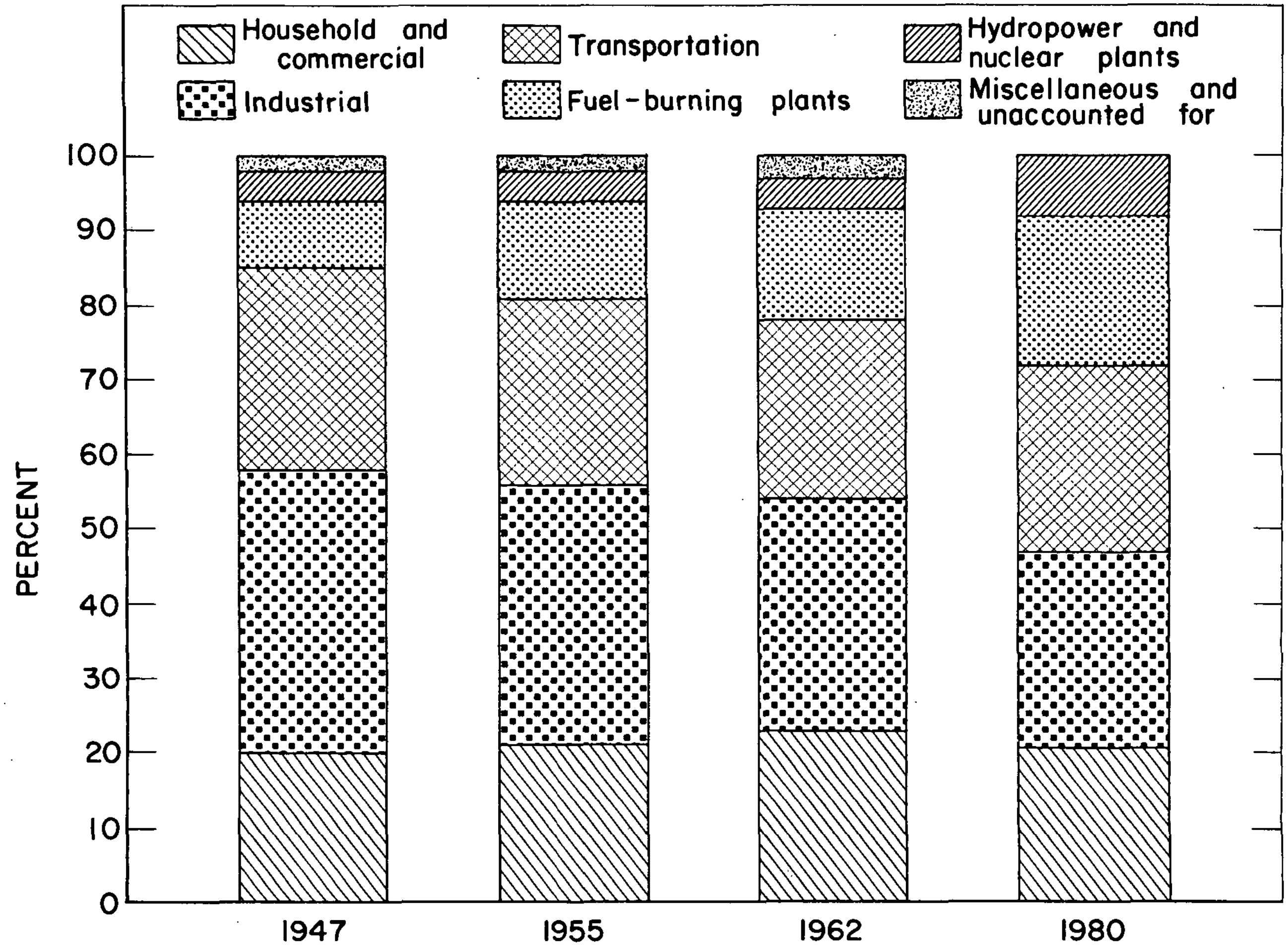

Figure 2.- Percentage Distribution of Total Energy by Consuming Sectors.

Bituminous coal and lignite and anthracite declined as energy sources because they virtually lost two major markets. In 1947, coal accounted for 50 and 34 percent, respectively, of the household and commercial and transportation markets. By 1962 its share of these markets had dropped to 8 percent of the household and commercial market and was negligible in the transportation market. Coal also suffered a severe decline in the share of the industrial market, from 57 to 32 percent. The same time it almost held its own in supplying fuel-burning electric generating plants suffering a relatively minor decline from 71 to 64 percent. But because fuel-generated electricity increased from 67 percent to 79 percent of total utility generation over the period, coal's share of this total actually increased from 47 to 50 percent.

The source of the growth in natural gas was apparently in all sectors. Its share increased from 17 to 44 percent in the household and commercial sector, from 23 to 42 percent in the industrial sector, and from 13 to 28 percent in the fuel-burning electric generating sector. Petroleum also increased its shares in the household and commercial and industrial markets and transportation but showed a decline in the fuel-burning electric generating market.

Energy Consumption by Function and Sector

A breakdown of energy consumption by function and consuming sector is contained in tables 5 through 14 for the same years. These tables are arranged so that the data for each year are presented, and then a percentage distribution by function and by sector follows. One of the highlights of this analysis is the relative stability of the distribution of uses of energy. The tables show, for example, that nonenergy uses have increased only from 4 percent of the total in 1947 to 5 percent of the total in 1962. The shift that occurred was a shift to consumption of energy as electricity. Here we see a change from 15 percent in 1947 to 21 percent in 1962, with a shift also between self-generated and utility electricity.

The series of tables on energy use by function are of most value when one turns to the competitive position of the various competing fuels. We will come back to this point after we take a look at the forecasts for 1980.

Forecasts for 1980

The forecasts for 1980, as presented in tables for that year, were made under certain assumptions. These include no major change in our international relations, an annual rate of growth of 4 percent in GNP and 1.6 percent in population, stability of the real cost of the primary energy sources both relative to each other and to the general level of commodity cost, a continuation of an evolutionary technology rather than a revolutionary one, the assumption of adequate supplies either domestic or imported to meet demands, and finally, the acceptance of the Federal Power Commission and the Atomic Energy Commission forecast that installed electric generation capacity in nuclear plants will reach 70,000 megawatts by 1980.

These forecasts were made after an intensive examination of trends indicated by the energy balances. The magnitude of expected error increases as one moves from the total energy to the energy by consuming sector to the energy by supplying source. The latter has always been the most erratic and can be expected to hold the major surprises in the future. Projections made here, it should be understood, are based upon the explicit assumption of no major new technological breakthroughs except nuclear energy.

It should be emphasized that forecasts made in the context of a total energy balance, and based upon relatively general indicators, are not necessarily the best for any given type of fuel. There is a wide range of competent forecasts for specific fuels, and my results are higher than the general consensus for some fuels and lower for others. The specific fuel forecast contains the highest degree of expected variability, on the order of plus or minus 30 percent. For this reason, these forecasts developed in this paper should not be interpreted as an alternative to specific fuel forecasts made by others, but should be used in the context of an analysis of energy source shifts and the impact of such shifts on a given fuel. The kind of analysis involved, looking at energy as a single commodity, is but one of many types that can be made. The forecasts are a result of this system of analysis, and should be interpreted within the context of the methodology, rather than as firm forecasts for planning.

The methodology of the forecast involved projection of least square trends of historical data and correlation between these data and other indicators.

An initial estimate was made of the rate of growth of total energy consumption by sector by correlating the various sectors with general economic indicators. The indicators used were GNP (for total energy), population (for the household and commercial sector), a composite variable consisting of new construction, producer, durable and personal consumption expenditures (for the industrial sector), and GNP (for the transportation sector). The electric utilities sector was taken from an advisory committee report (No. 21) for the National Power Survey of the Federal Power Commission. From this analysis, estimates of total consumption and of consumption by consuming sector were determined. These markets were then allocated to energy sources by subjecting the least squares projections of each source to analysis and judgment based on knowledge of the energy industries and markets, consensus of outside experts, and examination of other functional energy forecasts.

The forecast shows that energy is expected to grow at an annual rate of 3.2 percent, considerably above the historical rate of 2.5 percent. All sectors except household and commercial are expected to grow at faster rates than during the historical period. The industrial growth is expected to be 2 percent per annum as compared to an historical 1 percent; transportation, 3.5 percent as compared to 1.75 percent; and electricity, 5.5 percent as compared to 5 percent.

From the point of view of sources of supply, some major shifts are indicated. Bituminous coal, which showed an average decline of 2.5 percent in the historical period, is expected to reverse itself and increase at a rate of 2.4 percent. Petroleum and natural gas are expected to show a decline in growth rate to rates of 3.0 and 3.5 percent, respectively. Hydropower is expected to continue a 2-percent growth rate, and anthracite will continue to decline but at a slower rate, about 2 percent a year. The major new element coming into the picture, becoming significant within a couple of years, is nuclear energy. It is expected to grow from a negligible proportion of the market in 1962 to supply almost 5 percent of the total energy market by 1980. This represents an annual rate of growth of 34 percent per year.

Competition Between Energy Sources

Given today's technology, there are apparently two sectors of energy consumption for which fuels compete on a price basis. These are the electric generation sector and the other heat portion of the industrial sector. This is essentially the boiler-fuel market. It is not an insignificant one. In 1962 it was 53 percent of the total energy market and by 1980 it is expected to be 56 percent of that market. Prior to the introduction of gas by pipeline into the major residential market, the household and commercial sector was considered a competitive market for fuels. Oil and coal were competing with each other for this market. However, the major technological breakthrough represented by the high-pressure large-diameter pipelines which brought gas to markets quickly altered the picture. Natural gas which supplied 17 percent in 1947 had increased its share to 44 percent by 1962 and, even further, is expected to increase its share to 58 percent by 1980. Today's household and commercial market met by energy in the form of fuel is the province of petroleum and natural gas. Coal is out for reasons that have little to do with price. The transportation market, with dieselization of the railroads, became the sole province of petroleum, although natural gas used in pipeline transportation represents a small but significant percentage of this market.

However, the growth of electricity is placing both the household and industrial markets to some degree again in a competitive position. In 1947 the household and commercial market obtained 30 percent of its energy by electricity. By 1962 this had grown to 36 percent and it is projected to grow to almost 50 percent by 1980. The generation of electricity is a competitive fuel market. A similar trend is recognizable in the industrial market, which got 16 percent of its energy from electricity in 1947, 20 percent in 1962, and a projected 27 percent in 1980. Thus, technology, while closing some markets to competition through a highly efficient production function in which the cost of fuel becomes a minor consideration, is also returning other markets to competition by switching to an energy form which can be supplied competitively from any of the source materials.

A Tentative Hypothesis

Major shifts have occurred among the sources of energy in the United States economy. These shifts have been described in the previous portions of this paper. The shifts between sources have been of much greater magnitude than the shifts in total energy consumption by sector. Therefore, it is obvious that the explanation for the changing demands for a specific mineral source must lie in its substitution by another energy source rather than the changing structure of the market itself. What are the determinants of this substitution? This is the fundamental question in analyzing the demand for a specific energy material and one upon which I want to venture a tentative hypothesis.

The theory of market demand as developed by economists sees three kinds of forces operating on the demand for a commodity. These are the structure of taste of consumers, the level of income of consumers, and the relative prices of the commodities. Given these three factors, one can construct a demand function for the commodity in concern. Such a function, assuming a given taste, will tell you by how much the actual quantity demanded of a commodity will change if incomes change and if prices change. In the case of a raw material, the demand function is derived from that of the finished commodity, and is a function of that demand and relative price. Such an analysis simply does not work for the energy raw materials in our economy. I know because I have tried it. This failure of traditional economic theory to explain the shifting patterns has caused me to put forward an alternative hypothesis. This hypothesis briefly stated is as follows: The shifting demands for energy source material are explained by the changing production functions in the consuming sectors, that is, by technological changes in the consuming sectors.

This hypothesis holds that a new technology in a consuming sector is very likely to be of such a nature that the energy commodities are not substitutes within it. A production function is chosen which requires certain characteristics of the energy source, but the cost of the energy meeting these characteristics was probably of very minor or negligible importance in the design of the total production function. For example, the dieselization of the railroads clearly was not made to save fuel cost. Coal lost the railroad market because the entire production function of providing motive power for railroads changed. The entire complex of service was cheaper from diesel-powered locomotives that from steam-powered locomotives. On an energy basis alone, there is no evidence that the fuel costs are any cheaper. The other costs simply outweighed the fuel costs in their entirety. If we look at the household and commercial market which coal has also lost, we find that the development of the technology of transmission of gas and the development of the automatic furnace together forced coal out of this market. The space saving, cleanliness, and convenience features were and are overwhelming. If price of energy were the factor here, we would see the rate of gas penetration slowing, since the price of gas has been rising steadily relative to other fuels for the last 20 years. This is not the case. Once again the technology determines the fuel source, and price changes within the fuel sources themselves cannot reverse this commitment.

To partially substantiate this hypothesis in an indirect way, look at the competitive area of the energy market, the so-called boiler-fuel market. Here the traditional economics apparently do apply and coal has done well in this market. The price relatives have favored coal throughout the entire period and even so, it has lost the major transportation and household and commercial markets.

If my hypothesis is acceptable, it means that analysis of the substitution of energy sources must be based squarely on the technology of and the rate and character of technological change in the consuming sectors. It cannot be based upon an analysis of the energy sources themselves. This forces the analyst interested in energy into an overall look at the entire economy and into the very difficult area of predicting technologic change. This is perhaps discouraging but nevertheless, I believe, true.

TABLE 1.-United States gross consumption of energy by major sources and consuming sectors, 1947 1/
(Trillion Btu)

Sources	Household and commercial	Industrial	Transportation 2/	Electric generation utilities: Fuel-burning plants	Electric generation utilities: Hydropower and nuclear plants	Misc. and unaccounted for	Total gross energy
Anthracite	812.8	284.7	23.9	89.5	------	13.3	1,224.2
Percent contribution	12	2	3/	3	------	3	4
Bituminous and lignite	2,585.5	7,013.6	3,006.2	1,994.4	------	-----	14,599.7
Percent contribution	38	55	34	68	------	-----	44
Natural gas, dry 4/	1,125.0	2,874.7	(neg)	386.1	------	132.6	4,518.4
Percent contribution	17	23	-----	13	------	24	14
Petroleum 5/	2,250.9	2,489.7	5,760.5	468.0	------	397.9	11,367.0
Percent contribution	33	20	66	16	------	73	34
Hydropower 6/	-----	-----	-----	-----	1,459.0	-----	1,459.0
Percent contribution	-----	-----	-----	-----	100	-----	4
Total gross energy	6,774.2	12,662.7	8,790.6	2,938.0	1,459.0	543.8	33,168.3
Percent contribution	100	100	100	100	100	100	100
Percentage distribution of total energy by consuming sector	20	38	27	9	4	2	100

1/ Gross energy is that contained in all types of commercial energy at the time it is incorporated in the economy whether the energy is produced domestically or imported. Gross energy comprises inputs of primary fuels (or their derivatives) and outputs of hydropower and nuclear power converted to theoretical energy inputs. Gross energy includes the energy used for the production, processing and transportation of energy proper.

2/ Includes bunkers and military transportation.

3/ Less than .05 percent.

4/ Excludes natural gas liquids.

5/ Petroleum products including still gas, liquefied refinery gas, and natural gas liquids.

6/ Represents outputs of hydropower and nuclear power converted to theoretical energy inputs at the prevailing rate of pounds of coal per kilowatt hour at central electric stations. Excludes inputs for power generated by non-utility plants, which are included within the other consuming sectors.

Sources: Compiled by Bureau of Mines, United States Department of the Interior, supplemented by data on hydropower and nuclear power from the Federal Power Commission and the Atomic Energy Commission.

TABLE 2.-United States gross consumption of energy by major sources and consuming sectors, 1955 1/
(Trillion Btu)

Sources	Household and commercial	Industrial	Transportation 2/	Electric generation utilities: Fuel-burning plants	Electric generation utilities: Hydropower and nuclear plants	Misc. and unaccounted for	Total gross energy
Anthracite	330.7	52.7	11.6	81.5	-----	122.9	599.4
Percent contribution	4	3/	3/	2	-----	13	1
Bituminous and lignite	1,443.7	5,796.1	462.1	3,402.1	-----	-----	11,104.0
Percent contribution	17	42	5	65	-----	-----	28
Natural gas, dry 4/	2,849.5	4,675.0	253.8	1,193.6	-----	260.1	9,232.0
Percent contribution	33	33	3	23	-----	27	23
Petroleum 5/	4,001.0	3,329.2	9,109.3	512.2	-----	572.3	17,524.0
Percent contribution	46	25	92	10	-----	60	44
Hydropower 6/	-----	-----	-----	-----	1,497.0	-----	1,497.0
Percent contribution	-----	-----	-----	-----	100	-----	4
Total gross energy	8,624.9	13,853.0	9,836.8	5,189.4	1,497.0	955.3	39,956.4
Percent contribution	100	100	100	100	100	100	100
Percentage distribution of total energy by consuming sectors	21	35	25	13	4	2	100

1/ Gross energy is that contained in all types of commercial energy at the time it is incorporated in the economy whether the energy is produced domestically or imported. Gross energy comprises inputs of primary fuels (or their derivatives) and outputs of hydropower and nuclear power converted to theoretical energy inputs. Gross energy includes the energy used for the production, processing and transportation of energy proper.
2/ Includes bunkers and military transportation.
3/ Less than .05 percent.
4/ Excludes natural gas liquids.
5/ Petroleum products including still gas, liquefied refinery gas, and natural gas liquids.
6/ Represents outputs of hydropower and nuclear power converted to theoretical energy inputs at the prevailing rate of pounds of coal per kilowatt hour at central electric stations. Excludes inputs for power generated by non-utility plants, which are included within the other consuming sectors.

Sources: Compiled by Bureau of Mines, United States Department of the Interior, supplemented by data on hydropower and nuclear power from the Federal Power Commission and the Atomic Energy Commission.

TABLE 3.-United States gross consumption of energy by major sources and consuming sectors, 1962 1/
(Trillion Btu)

Sources	Household and commercial	Industrial	Transportation 2/	Electric generation utilities: Fuel-burning plants	Electric generation utilities: Hydropower and nuclear plants	Misc. and unaccounted for	Total gross energy
Anthracite	121.1	49.0	(neg.)	58.2	-----	152.7	381.0
Percent contribution	1	3/	-----	1	-----	12	1
Bituminous and lignite	798.6	4,761.6	19.5	4,580.0	-----	-----	10,159.7
Percent contribution	7	32	3/	63	-----	-----	21
Natural gas, dry 4/	4,849.2	6,293.2	395.8	2,034.4	-----	548.2	14,120.8
Percent contribution	44	42	4	28	-----	43	30
Petroleum 5/	5,227.1	3,879.7	11,000.9	579.0	-----	580.3	21,267.0
Percent contribution	48	26	96	8	-----	45	44
Hydropower 6/	-----	-----	-----	-----	1,943.0	-----	1,943.0
Percent contribution	-----	-----	-----	-----	99	-----	4
Nuclear 6/	-----	-----	-----	-----	25.9	-----	25.9
Percent contribution	-----	-----	-----	-----	1	-----	3/
Total gross energy	10,996.0	14,983.5	11,416.2	7,251.6	1,968.9	1,281.2	47,897.4
Percent contribution	100	100	100	100	100	100	100
Percentage distribution of total energy by consuming sector	23	31	24	15	4	3	100

1/ Gross energy is that contained in all types of commercial energy at the time it is incorporated in the economy whether the energy is produced domestically or imported. Gross energy comprises inputs of primary fuels (or their derivatives) and outputs of hydropower and nuclear power converted to theoretical energy inputs. Gross energy includes the energy used for the production, processing and transportation of energy proper.
2/ Includes bunkers and military transportation.
3/ Less than .05 percent.
4/ Excludes natural gas liquids.
5/ Petroleum products including still gas, liquefied refinery gas, and natural gas liquids.
6/ Represents outputs of hydropower and nuclear power converted to theoretical energy inputs at the prevailing rate of pounds of coal per kilowatt hour at central electric stations. Excludes inputs for power generated by non-utility plants, which are included within the other consuming sectors.

Sources: Compiled by Bureau of Mines, United States Department of the Interior, supplemented by data on hydropower and nuclear power from the Federal Power Commission and the Atomic Energy Commission.

TABLE 4.-United States gross consumption of energy by major sources and consuming sectors, 1980 1/
(Trillion Btu)

				Electric generation utilities			
Sources	Household and commercial	Industrial	Transportation 2/	Fuel-burning plants	Hydropower and nuclear plants	Misc. and unaccounted for	Total gross energy
Anthracite	50.0	50.0	(neg.)	150.0	-----	-----	250.0
Percent contribution	3/	3/	-----	1	-----	-----	3/
Bituminous and lignite	200.0	3,475.8	-----	12,416.0	-----	-----	16,091.8
Percent contribution	1	16	-----	71	-----	-----	19
Natural gas, dry 4/	10,366.8	11,537.5	693.0	3,918.3	-----	-----	26,515.6
Percent contribution	58	52	3	23	-----	-----	31
Petroleum 5/	7,362.2	7,167.9	20,649.7	861.7	-----	-----	36,041.5
Percent contribution	41	32	97	5	-----	-----	42
Hydropower 6/	-----	-----	-----	-----	2,674.5	-----	2,674.5
Percent contribution	-----	-----	-----	-----	38	-----	3
Nuclear 6/	-----	-----	-----	-----	4,361.0	-----	4,361.0
Percent contribution	-----	-----	-----	-----	62	-----	5
Total gross energy	17,979.0	22,231.2	21,342.7	17,346.0	7,035.5	-----	85,934.4
Percent contribution	100	100	100	100	100	-----	100
Percent distribution of total energy by consuming sector	21	26	25	20	8	-----	100

1/ Gross energy is that contained in all types of commercial energy at the time it is incorporated in the economy whether the energy is produced domestically or imported. Gross energy comprises inputs of primary fuels (or their derivatives) and outputs of hydropower and nuclear power converted to theoretical energy inputs. Gross energy includes the energy used for the production, processing and transportation of energy proper.
2/ Includes bunkers and military transportation.
3/ Less than .05 percent.
4/ Excludes natural gas liquids.
5/ Petroleum products including still gas, liquefied refinery gas, and natural gas liquids.
6/ Represents outputs of hydropower and nuclear power converted to theoretical energy inputs at the prevailing rate of pounds of coal per kilowatt hour at central electric stations. Excludes inputs for power generated by non-utility plants, which are included within the other consuming sectors.

Sources: Compiled by Bureau of Mines, United States Department of the Interior, supplemented by data on hydropower and nuclear power from the Federal Power Commission and the Atomic Energy Commission.

TABLE 5.-United States gross consumption of energy by function and consuming sector, 1947 (Trillion Btu)

Function	Household and commercial	Transportation	Industrial	Total function
Space heat------------------	3,994	94	439	4,527
Other heat------------------	2,454	--	10,462	12,916
Total heat-------------	6,448	94	10,901	17,443
Utility electricity---------	2,880	70	1,447	4,397
Self-generated electricity--	0	0	732	732
Total electricity------	2,880	70	2,179	5,129
Motive use------------------	---	8,697	---	8,697
Non-energy uses-------------	326	--	1,030	1,356
Total sector-----------	9,654	8,861	14,110	33,168 1/

1/ Parts do not add to total because miscellaneous category left out; about 2% of total; 544 in 1947.

TABLE 6.-Percent distribution of gross consumption of energy of each sector by function, 1947

Function	Household and commercial	Transportation	Industrial	Total function
Space heat------------------	41	1	3	14
Other heat------------------	26	0	74	39
Total heat-------------	67	1	77	53
Utility electricity---------	30	1	11	13
Self-generated electricity--	--	--	5	2
Total electricity------	30	1	16	15
Motive use------------------	0	98	0	26
Non-energy uses-------------	3	0	7	4
Total sector-----------	100	100	100	100 1/

1/ Parts do not add to total because miscellaneous left out; 2% of total in 1947.

TABLE 7.-Percent distribution of gross consumption of energy by each function by sector, 1947

Function	Household and commercial	Transportation	Industrial	Total function
Space heat------------------	88	2	10	100
Other heat------------------	19	0	81	100
Total heat------------	37	1	62	100
Utility electricity---------	65	2	33	100
Self-generated electricity--	--	-	100	100
Total electricity------	56	1	43	100
Motive use------------------	0	100	0	100
Non-energy uses-------------	24	0	76	100
Total sector-----------	29	27	42	100 1/

1/ Parts do not add to total because miscellaneous category left out; 2% of total in 1947.

TABLE 8.-United States gross consumption of energy by function and consuming sector, 1955 (Trillion Btu)

Function	Household and commercial	Transportation	Industrial	Total function
Space heat------------------	4,987	104	532	5,623
Other heat------------------	3,023	---	11,470	14,493
Total heat------------	8,010	104	12,002	20,116
Utility electricity---------	4,393	46	2,247	6,686
Self-generated electricity--	0	0	761	761
Total electricity------	4,393	46	3,008	7,447
Motive use------------------	---	9,733	---	9,733
Non-energy uses-------------	615	---	1,090	1,705
Total sector-----------	13,018	9,883	16,100	39,956 1/

1/ Parts do not add to total because miscellaneous category left out; about 2% of total; 955 in 1955.

TABLE 9.-Percent distribution of gross consumption of energy of each sector by function, 1955

Function	Household and commercial	Transportation	Industrial	Total function
Space heat	38	1	3	14
Other heat	23	0	71	36
Total heat	61	1	74	50
Utility electricity	34	1/	14	17
Self-generated electricity	--	-	5	2
Total electricity	34	1/	19	19
Motive use	0	99	0	25
Non-energy uses	5	0	7	4
Total sector	100	100	100	100 2/

1/ Less than .5%.
2/ Parts do not add to total because miscellaneous left out; 2% of total in 1955.

TABLE 10.-Percent distribution of gross consumption of energy by each function by sector, 1955

Function	Household and commercial	Transportation	Industrial	Total function
Space heat	89	2	9	100
Other heat	21	-	79	100
Total heat	40	1/	60	100
Utility electricity	66	1	33	100
Self-generated electricity	0	0	100	100
Total electricity	59	1	40	100
Motive use	--	100	--	100
Non-energy uses	36	--	64	100
Total sector	33	25	40	100 2/

1/ Less than .5%.
2/ Parts do not add to total because miscellaneous category left out; 2% of total in 1955.

TABLE 11.-United States gross consumption of energy by function and consuming sectors, 1962
(Trillion Btu)

Function	Household and commercial	Transportation	Industrial	Total function
Space heat	6,793	133	685	7,611
Other heat	3,399	0	11,982	15,381
Total heat	10,192	133	12,667	22,992
Utility electricity	6,279	46	2,895	9,220
Self-generated electricity	0	0	747	747
Total electricity	6,279	46	3,642	9,967
Motive use	0	11,283	0	11,283
Non-energy use	804	0	1,570	2,374
Total sector	17,275	11,462	17,879	47,897 1/

1/ Parts do not add to total. Miscellaneous category not included; 1,281 trillion Btu, 2.6% of total.

TABLE 12.-Percent distribution of gross consumption of energy of each sector by function, 1962

Function	Household and commercial	Transportation	Industrial	Total function
Space heat	39	1	4	16
Other heat	20	0	67	32
Total heat	59	1	71	48
Utility electricity	36	2/	16	19
Self-generated electricity	0	0	4	2
Total electricity	36	2/	20	21
Motive use	0	99	0	23
Non-energy use	5	0	9	5
Total sector	100	100	100	100 1/

1/ Parts do not add to total. Miscellaneous category not included; 1,281 trillion Btu, 2.6% of total.
2/ Less than .5%.

TABLE 13.-Percent distribution of gross consumption of energy of each sector by function, 1962

Function	Household and commercial	Transportation	Industrial	Total function
Space heat------------------	89	2	9	100
Other heat------------------	22	0	78	100
Total heat-------------	44	1	55	100
Utility electricity---------	68	1	31	100
Self-generated electricity--	0	0	100	100
Total electricity------	63	2/	37	100
Motive use------------------	0	100	0	100
Non-energy use--------------	34	0	66	100
Total sector-----------	36	24	37	100 1/

1/ Parts do not add to total; miscellaneous category not included; 2.6% of total.
2/ Less than .5%.

TABLE 14.-United States gross consumption of energy by function and consuming sectors, 1980
(Trillion Btu)

Function	Household and commercial	Transportation	Industrial	Total function
Space heat------------------	9,780	150	872	10,802
Other heat------------------	6,199	---	16,381	22,580
Total heat-------------	15,979	150	17,253	33,382
Utility electricity---------	17,504	70	6,807	24,381
Self-generated electricity--	0	0	1,108	1,108
Total electricity------	17,504	70	7,915	25,489
Motive use------------------	---	21,193	---	21,193
Non-energy uses-------------	2,000	---	3,870	5,870
Total sector-----------	35,483	21,413	29,038	85,934

TABLE 15.-Percent distribution of gross consumption of energy of each sector by function, 1980

Function	Household and commercial	Transportation	Industrial	Total function
Space heat------------------	28	1	3	12
Other heat------------------	17	0	57	26
Total heat-------------	45	1	60	38
Utility electricity---------	49	1/	23	29
Self-generated electricity--	--	-	4	1
Total electricity------	49	1/	27	30
Motive use------------------	0	99	0	25
Non-energy uses-------------	6	0	13	7
Total sector-----------	100	100	100	100

1/ Less than .5%.

TABLE 16.-Percent distribution of gross consumption of energy by each function by sector, 1980

Function	Household and commercial	Transportation	Industrial	Total function
Space heat------------------	91	1	8	100
Other heat------------------	27	0	73	100
Total heat-------------	48	1/	52	100
Utility electricity---------	72	1/	28	100
Self-generated electricity--	0	0	100	100
Total electricity------	69	1/	31	100
Motive use------------------	0	100	0	100
Non-energy uses-------------	34	0	66	100
Total sector-----------	41	25	34	100

1/ Less than .5%.

THE UTILIZATION OF COAL

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ABSTRACT

A brief survey is presented of current and prospective utilization of coals, including lignite, (1) in the production of metallurgical, chemical and specialty cokes, (2) as fuel for process steam, space and home heating, locomotives and ship bunkers, (3) in the manufacture of industrial producer gas and gas for chemical synthesis, (4) as fuel in cement and lime kiln firing, (5) at steel and rolling mills and (6) in a variety of specialty and/or non-fuel uses, including industrial carbons, active carbon, fillers, filter aids and media, water treatment, foundry facing, road building, roofing and coating applications, barbecue briquets, fertilizer and soil conditioner, coal-based plastics, etc.

Insofar as possible, information is presented on process and product research and other developments that may affect coal utilization, favorably or unfavorably, in the areas cited. Since economics of coal utilization cannot be divorced from economics of coal supply and transportation, these are touched upon briefly although they are subjects of separate presentations in the Symposium.

UTILIZATION OF PETROLEUM AND PETROLEUM PRODUCTS

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Petroleum has been utilized by man throughout most of his stay on this planet. An ancient Babylonian tablet reports, for example, that Noah calked his Ark with bitumen. This story suggests that petroleum was used before the advent of recorded history(3). Up until fairly recent times, however, crude oil and its products were quite scarce and its consumption was limited.

In the mid-1800's, the oil industry as we now know it emerged. This development was made possible when Colonel Drake improved the technology then in use for drilling salt wells and drilled instead for oil in 1859. The Drake well, which was the first well deliberately drilled for oil, was successful and resulted in production of eight to ten barrels of oil a day. As Colonel Drake's approach came into widespread use, crude oil production rose rapidly and during the next year total domestic crude oil production was 500,000 barrels. One year later over two million barrels were produced. The costs of crude oil declined sharply as production rose, and petroleum utilization increased rapidly.

The broad expansion of oil markets that came about after 1859 was made possible by many factors including: (1) high and rising prices for animal and vegetable oils, (2) a radically improved technique of exploration and production, and (3) improved techniques of utilization. This experience illustrates the fact that the utilization of petroleum is the resultant of a wide variety of forces which ultimately make themselves felt in the market place. The equilibrium achieved, however, is quite fragile and changes in the underlying forces lead to continued and sometimes rapid shifts in utilization patterns. Hence, in discussing utilization, it is not sufficient to consider existing or potential technology of oil consumption alone. It is also necessary to indicate the effects of potential changes in supply and of new competitive forces. Any projection of utilization must contain, at least implicitly, some assumptions about future supply and competing technology as these factors can have important consequences today. Thus an anticipated shortage of a particular form of energy some years in the future leads consumers to begin searching for ways to economize in the use of the resource or to convert to alternate sources today. Producers begin to look for new supplies or to improve methods of producing known deposits. Producers of competing fuels search for ways to substitute their products for the one in short supply. All of these activities tend to delay or to prevent an actual scarcity.

This point is well illustrated in the case of petroleum. The rapid rise in crude oil production after the Drake discovery led to increasing fears that the industry would be unable to continue meeting the demands being made upon it. In 1909, when the industry was a mature half century old, the U. S. Geological Survey expressed the fear that the nation's petroleum resources would soon prove inadequate to meet the needs of industry and suggested further that, in the face of approaching scarcity, petroleum should be limited to uses where there were no reasonable substitutes such as lubrication and illumination(5). The introduction of geological techniques to the oil-finding process around the turn of the century, however, eventually ushered in a new era of oil discovery which prevented the anticipated scarcity from developing.

The rapid acceptance and growth in the use of the automobile led to an even greater demand on resources and the cry of forthcoming shortage was again heard through the land. A leading professor of engineering here in Michigan typified this view when he stated in 1920 that the gasoline powered vehicle would have to be abandoned by 1940 at the latest because of a shortage of petroleum(1). The subsequent introduction of geophysical techniques and their gradual improvement ushered in an era of discoveries so great, however, that within a fairly short period overproduction, not shortage, became the major problem.

The forecasts of shortage just cited were not isolated events. Competent authorities have forecast impending scarcity almost since the inception of the oil industry. The important point is that the threat of scarcity so stimulated research that shortages were effectively forestalled. Furthermore, research was continuing simultaneously on a wide variety of substitutes, which could conceivably have filled the gap, at no dramatic increase in cost, if oil resources had not kept pace with requirements. Developments in these areas have influenced utilization at least as much as have technical improvements in the consumption of energy.

TECHNOLOGY OF PETROLEUM UTILIZATION

In reviewing present and potential utilization patterns, it is useful to begin with the current state of consuming technology and the developments which appear most likely to occur in the near term future. This technology enables us to make a reasonable estimate of the demands which will be made on resources over the period of a decade or two. Using our present knowledge of the nation's resources we can then determine whether or not the demand pattern appears reasonable and, if not, we can adjust it as necessary.

In the longer term future our ability to predict is increasingly inaccurate, and we do not have a clear picture today of the technology or the resources which will be available more than about twenty years from now. The repeated groundless fears of shortage in the past indicate that it is probably unwise to determine capital budgets, formulate research policy, or even establish national policies on the basis of developments which are anticipated more than twenty years or so in the future. Longer range forecasts serve to indicate potential trouble spots which should be watched, but they do not serve as a reliable guide for policy today.

In projecting future demand patterns it is also necessary to make some explicit or implicit assumptions about the relative prices of fuels. For the present we shall assume that relative prices will be unchanged for the foreseeable future. Subsequently we shall inquire whether this assumption is reasonable or whether there are factors which would make petroleum increasingly costly relative to competing fuels and which would hence necessitate a modification of the projection.

Transportation

In the United States approximately 50 per cent of all the oil consumed is used in the transportation sector. Oil has over 90 per cent of this market. Abroad, these percentages are probably somewhat lower, but they are not radically different from the levels prevailing in the U. S. Since oil cannot increase appreciably its market share, its growth in this market is essentially limited to the overall growth in the transportation sector.

There are a wide variety of technological developments which could have an impact on the transportation market. For personal transportation, however, there appears to be little threat to the hydrocarbon powered vehicle, at least for the next twenty years. Most of the devices which might compete with the gasoline-powered piston engine are hydrocarbon engines themselves. Among these are the gas turbine; the light-weight, high-speed diesel engine; the stratified charge engine; the free-piston engine; the Stirling engine; and the NSU rotary combustion engine. Based on present information, none of these engines presents a major threat to the gasoline piston engine, although highway diesel use is growing. In the longer run, there may be some shift toward the stratified charge and the gas turbine engine. None of these changes, however, would seriously affect the total demand for hydrocarbons although they might necessitate a shift away from gasoline toward middle distillates in the refining process.

It is possible that the battery or fuel cell may replace the gasoline piston engine in a limited number of special vehicles primarily used for city driving. The probability of this development appears quite small, however. Either device would require a technological breakthrough to be economic and, even if such a breakthrough should occur, these devices probably would not capture a large segment of the private transportation market in the foreseeable future. Furthermore, a workable fuel cell has a reasonable probability of requiring hydrocarbons as a fuel. For these reasons, it is not considered likely that either battery or fuel cell powered automobiles will have a significant impact on petroleum demand for the next twenty years although they could affect demand in the longer run.

Railroads are another segment of the transportation market in which oil is dominant. The rapidity with which the railroads converted to diesels following World War II shows that significant changes can take place in short periods of time. The major threat to oil in this market is electrification. This threat is more potential than real for the foreseeable future, however, as substantial new electrification projects probably cannot be justified in the U. S. until such time as railroad mergers and rerouting of lines result in higher traffic density. Gas turbines may ultimately replace diesels in some railroad applications but, in any event, most of this market appears to be secure for hydrocarbons for at least twenty years and probably much longer.

In the area of marine transportation the major threat to oil comes from nuclear energy. Although it is unlikely that nuclear energy can compete economically with hydrocarbon engines in the U. S. in private marine transportation over the next twenty years, it will be of growing importance in military applications. Abroad, introduction of nuclear energy in marine transportation will probably be inhibited by capital limitations.

The aviation market appears quite safe for hydrocarbons in the years ahead. The rapidity with which the gas turbine replaced the piston engine in this market argues strongly against oil industry complacency, but the technological developments in the offing do not appear to be of a nature to challenge oil's dominance of this market.

The future of oil in the important transportation sector can be readily summarized as follows:

1. Because of oil's overwhelming position in the transportation market, its growth in this area will be largely limited by the growth of the market, particularly in the U. S. The additional volumes which will be consumed in this sector in the U. S. will be quite large, but the annual average growth rate here will be somewhat lower than the growth rates anticipated abroad.

2. There are no new technological developments in sight which seriously threaten hydrocarbon fuels in the transportation market in the foreseeable future.

3. There may be shifts in demand away from gasoline toward middle distillates in the U. S., but any such shifts are expected to be gradual and are not expected to affect the overall demand for petroleum significantly.

Industry and Power Plant Use

General industry and power plant use constitute a second market for oil. Most of the petroleum fuel supplied to this market is in the form of heavy fuel oil. In the U. S. oil is not a major factor in this segment. It accounts for about 7 per cent of the steam electric power plant fuel used by utilities and about 13 per cent of the manufacturers' heat and power market. In addition to these uses, oil will be of increasing importance in specialized industrial uses. For example, a pound of oil can displace 1.6 pounds of coke in blast furnaces with significant savings. Ore reduction and fertilizer manufacture also represent large potential markets for oil.

The future of oil in the industrial markets of the U. S. is determined by factors other than technology of utilization, however. The domestic production of heavy fuel oil is declining as refiners continually improve their yield patterns and it is now equal to only about one half of domestic consumption. Imports of heavy fuel oil, which make up the balance, are limited by the Oil Imports Administration in such a manner that the total domestic supply of heavy fuel oil has been held fairly constant since the inception of the program. It is, of course, impossible to project with confidence the import policies of the future, but it is clear that if the controls limit the supply to a fixed level, as they have in the past, they will serve to prevent increased industrial oil consumption in the U. S. as a result of either normal growth or of new technology. Furthermore, widespread improvements in transporting coal will probably result in some further reduction in delivered coal prices which will make coal more competitive. Abroad, however, there is quite a different story. Oil will be increasingly important to general industry and, for the foreseeable future, rapid expansion in the generation of electricity will increase the demand for oil despite probable nuclear developments. Coal costs will continue to rise in Europe and there is some hope for reducing the punitive excise taxes levied against heavy fuel oil in much of Europe today. As a result, oil should become increasingly competitive outside the U. S.

Residential and Commercial Consumption

The residential and commercial sector is another major petroleum market. Gas dominates the space heating component, however, and electricity is the major factor in the air cooling segment. Oil--largely in the form of middle distillates --supplies about one third of the total energy consumed in this market.

Oil's share of the space heating market is under attack by both natural gas and electricity, particularly in multi-unit dwellings. Natural gas has accounted for most of the growth of this market in recent years but electricity is a growing threat to both gas and oil. More new homes were heated by gas than electricity last year and more were heated by electricity than by oil.

Further threats to oil's position in the residential and commercial market are posed by research on thermoelectric heating and cooling and on gas-fired absorption cycle combination heating-cooling units. On the other hand, oil's position is being strengthened by research on oil-fired absorption cycle units and hydrocarbon fuel cells which can be used to supply electricity to individual residences or to groups of consumers in limited areas.

A significant technological breakthrough would be required before any of these potential new uses would be able to alter utilization patterns appreciably and it is not at all clear today what the net effect on petroleum demand is likely to be. It is also worthwhile to note that given the assumption of adequate resources and no significant changes in relative prices, there is no overwhelming national urgency for conducting such research as far as civilian uses are concerned.

Total Petroleum Demand

Most students of the petroleum industry are in agreement that if there are no unforeseen technological breakthroughs by oil or by competing forms of energy and if relative energy prices remain essentially unchanged, petroleum demand will grow in the United States at 2 to 3 per cent a year over the next decade or two. In foreign areas, where the growth potential is greater and where supply is less likely to be directly limited by import controls, petroleum demand already exceeds that of the U. S. and annual growth rates will be about twice as great as those expected in the U. S.

ADEQUACY OF SUPPLY

The demand projections of the previous section are predicated on the assumption of no change in relative prices. If, however, petroleum resources should prove inadequate to meet expected demand and if prices should rise, the future demand patterns would diverge from the projected levels. It is important, therefore, to balance projected demand against the resources which can be made available during the period in question.

If the domestic consumption of petroleum products should grow at the indicated upper level of 3 per cent a year, total consumption would exceed 100 billion barrels during the next twenty years. The resulting draft on domestic resources would depend on the administration of the import control program and the amount of natural gas liquids produced, but it is not unreasonable to assume that the projected demand pattern implies the production of 70 to 80 billion barrels of domestic crude oil during the next two decades. The domestic industry had not produced quite this much oil after the first century of its existence. Is it likely that it can produce this huge quantity in the next twenty years or are the pessimists, who feel this is an impossible burden, correct? Even if it is physically possible to produce this volume, can it be done at competitive prices? Given the assumption of an unchanged import program, these questions must be answered in the affirmative if the preceding demand projection is to be accepted.

One's answer to these questions depends on his estimate of the petroleum content of known petroleum reservoirs and those to be discovered during the forecast period, on the quality of these reservoirs and on future developments in techniques of production.

One highly competent authority has estimated that the domestic industry can develop at least 70 billion barrels of reserves in the next two decades from fields which have already been found and from fields which will be found on acreage which is already partially explored and is currently under lease(4). I see no reason to challenge this view. It must also be kept in mind that the nation's potentially productive sediments are far from explored. Another authority has estimated that less than one fifth of the nation's potentially productive sediments have been explored with any degree of thoroughness(6).

It would be most unwise to write off in advance these unexplored sediments as unproductive. Many potentially productive areas have been subject to little if any reconnaissance exploration. Furthermore, the sensitivity of our existing exploratory tools is such that we are frequently unable to locate valuable deposits by surface efforts alone. In particular, we are generally unable to locate stratigraphic traps through such surface efforts and some of the world's largest known fields have been found in such traps. As we extend our efforts to the largely unexplored areas, as we gather additional information through drilling in all areas, and as we continually improve the accuracy of our geophysical equipment it is almost inevitable that we shall discover additional large volumes of oil. Furthermore, there is every reason to believe that we shall be able to continue the long evident trend of increasing recovery of oil in place.

There is thus no convincing evidence that a physical scarcity of resources will inhibit petroleum production in the foreseeable future. Oil whose presence is already known or whose existence may be logically inferred is adequate for twenty years of consumption. In addition much more oil, whose existence can only be conjectured today, will undoubtedly be found or made available through improved recovery. To the extent that such oil becomes available, the period when physical scarcity will begin to inhibit consumption will be deferred into the unascertainable future.

The oil shale deposits in the U. S. and the tar sands in Canada provide further assurance that resources will not be a limiting factor on petroleum utilization in the foreseeable future. Not only are these resources immense in terms of oil in place, but large volumes of oil can probably be produced from them profitably at prices which are nearly competitive with crude oil.

Resources outside the U. S. are even more plentiful relative to demand than in the U. S. Thus there is less likelihood of shortage abroad than in the U. S. Furthermore, the discussion of U. S. resource adequacy assumed continuation of import regulations similar to those in effect today. If for some reason oil should not be found in anticipated volumes in this nation, import controls could be relaxed. Total free world resources are undoubtedly quite adequate to meet all anticipated demands over the foreseeable future.

Although resources in total may not serve to limit utilization it is possible that exploitation of increasingly inferior resources in certain areas such as the U. S. could lead to rising costs which would, in turn, inhibit demand in those areas.

In the U. S., for example, there has been a clearly discernible pattern of drilling to greater depth and moving toward less accessible deposits--notably those under the Gulf of Mexico and the West Coast offshore. Thus, it might be presumed that increasing costs of production might soon lead to higher prices which would be a limiting factor on utilization even if physical presence of resources were not an applicable constraint.

Although the hypothesis of increasing unit costs resulting from depletion of the more economical resources appears reasonable on the surface, an important recent study by Resources for the Future casts serious doubt on its validity(2). Improved technology in exploration and production have, according to this study, more than offset those factors which otherwise would have led to rising costs. There is no evidence of a reversal in this trend as of today and no logical reason to posit one in the foreseeable future. Accordingly, it appears likely from what we know today that petroleum prices will not rise relative to all other prices in the forecast period. This conclusion is reinforced by the fact that shale oil would probably come into production quite rapidly were crude oil prices to rise appreciably. Thus the magnitude of our crude oil resource base combined with potential competition from shale oil and other fuels will quite probably serve to keep crude oil prices from rising appreciably in the U. S.

One potential threat to oil markets--and a further safety factor for hydrocarbon consumers--is the production of liquid fuels from coal. Research is currently underway to develop economical techniques for producing such fuels from coal. To the extent that this research is successful it will, of course, reduce the demand for crude oil. There have been some interesting recent developments in coal liquefaction but, nevertheless, at present there is no convincing evidence that coal will displace any significant volume of petroleum in the liquid fuels market. This view is apparently fairly widespread since very few companies believe such research is sufficiently attractive to warrant the use of their own funds and the bulk of the work being done in this area is under Federal contract. Coal liquefaction is an interesting speculation but, given the information available today, it does not appear to pose a real threat to oil in the foreseeable future. Furthermore, if adequate supplies of all fuels will be forthcoming at no significant change in real prices over the foreseeable future, then there is little, if any, economic justification for federally sponsored research in this area.

CONCLUSIONS

The demand for petroleum products in the U. S. will probably grow at a rate of 2 or 3 per cent a year. Abroad, the annual growth rate will be perhaps twice as great as the rate in the U. S. Resources will not be a limiting factor either in the U. S. or the free world and there should be no significant shift in relative fuel prices in the foreseeable future.

It is unlikely that oil demand will be increased appreciably in the U. S. through research in utilization. Research on improved exploratory and productive techniques will probably have a greater influence on domestic oil demand than will research on oil utilization. Research on new uses is likely to have a much stronger influence on foreign utilization, however, than is the case within the U. S. The changes in oil utilization which appear most probable will not alter the growth rate of oil demand in the U. S. so much as its composition.

Finally, some research is being conducted today on the supposition that crude oil is in limited supply and hence that refined product prices are likely to rise in the near future relative to prices of competing fuels. Those undertaking research on these grounds are likely to be disappointed just as they have been in the past. Such research may represent an interesting speculation, but there is no overwhelming national urgency or profit incentive to develop substitutes for crude oil and its products.

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Gas Utilization Today and in the Future

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Before beginning this discussion on the utilization of gas, let me provide some brief background on the present status of gas in the Nation's aggregate energy requirements. Subsequently, we will examine the future of gas utilization, some of the economic problems associated with this industry, and some challenges to research and technology within the industry.

The gas industry had its infancy in the early nineteenth century with the first limited distribution of low Btu gases manufactured from coal. As recently as 1940, nearly 60 percent of the industry's customers were still dependent either upon manufactured gases (from coal or oil) or mixtures of manufactured and natural gas. To be sure, substantial portions of the country had been using natural gas for many years before this, where the gas was produced more or less locally. However, the rapid growth of the gas industry, and the major extension of natural gas availability to all portions of the Nation which facilitated this growth, was initiated in 1931 with the construction of Natural Gas Pipeline Company from Texas and Oklahoma to the Chicago area. It accelerated substantially in subsequent years as the availability of high-strength steel pipe and effective welding techniques made long-distance transportation of natural gas economically and physically feasible.

Until after World War II, supplies of natural gas available for delivery substantially exceeded the ability of the pipeline network to market the gas. It was a buyer's market and natural gas in the field was sold, frequently as a by-product of oil production and under incremental pricing theories, at prices which in retrospect appear extremely low. Immediately after World War II, coal and oil prices rose substantially and suddenly natural gas became the cheapest source of energy for a multitude of purposes, in most parts of the country. Pipeline construction accelerated markedly, and transmission lines were built to virtually every corner of the country. The additional requirements created by these new pipelines affected the supply-demand relationship substantially. Producers soon realized that they no longer were marketing a troublesome and relatively undesirable by-product for which they would accept almost any price, but were the proud possessors of an extremely desirable commodity of substantial value. The average price of natural gas in the field rose from 4.9 cents in 1945 to 10.4 cents in 1955. In my own opinion, this is in the best American tradition, that a product available in limited supply should bring increasingly higher prices as the demand increases. This is the surest way to encourage the introduction of new producers, thus increasing the available supply, and bringing the price down. Since 1961, the average price of natural gas in the field has indeed stabilized, although whether this is primarily attributable to the forces of economics, or because of regulatory actions of the Federal Government is a question I shall not discuss here. And, at the present time, over 98 percent of the gas distributed by utilities in the United States is pure natural gas.

Let us now discuss the components of this nation-wide demand for natural gas--the different types of consumers, and different types of applications. In the field of heating, the growth has been phenomenal. The total number of residential customers using natural gas for heating their homes has risen from 7.4 million in 1949 to 24.0 million in 1963. These totals exclude substantial numbers of families in multi-family structures where gas is used in central heating systems, and exclude significant numbers of households using liquefied petroleum gas for heating in areas beyond gas utility mains. The gas companies have been adding between one million and one and one-fourth million new residential heating customers each year for the past five years, and anticipate a continuation of this growth rate in the foreseeable future. In the preponderance of the Nation, natural gas is the cheapest heating fuel, not only for residential customers, but also for commercial and industrial establishments, to say nothing of its other desirable attributes. In our service area in northern Illinois, for instance, natural gas for residential use costs 35 percent less than oil, 15 percent less than coal, and 70 percent less than electric heating. These favorable economic circumstances are not unusual, and we expect that they will continue to prevail in the future. Ninety-nine percent of the new homes in our service area install gas heating in areas within reach of our mains, and we try vigorously to reach almost everyone.

In the residential market, basic household gas appliances have also shown marked growth, although not at the same rate as heating. For example, Chart 1 shows the growth of gas cooking as reported in the various United States Censuses of Housing. If Census data were available for years prior to 1960 for water heating, an even more rapid growth would be apparent. These growth rates have been lower than that for heating for one significant reason. To a major extent for cooking and clothes drying, and to a lesser extent for water heating, operating cost is not a crucial factor in consumer fuel decisions during decades of ever-higher economic activity. Annual operating costs are relatively small regardless of the fuel used, because of the modest energy requirements of these applications. Accordingly, although gas is the least costly form of energy, it must also compete in terms of qualitative and subjective features associated with the respective appliance. Some of our competitors produce attractive and well-designed equipment, and advertise it nationally on a massive scale. We welcome this kind of spirited competition, and we are confident that we will more than hold our own in the residential appliance market of the future.

The growth in commercial use of gas for non-heating applications has also been very substantial. Cost factors are important to a commercial establishment, which is more concerned with its own profit and loss than with advertising messages and subjective evaluation. Surveys done at periodic intervals among the best restaurants throughout the Nation confirm an overwhelming and consistent use of gas for cooking in excess of 90 percent. Further favorable evidence is available from the acceptance of gas at the New York World's Fair where gas is being used for 80 percent of the cooling, 90 percent of the heating and water heating, and 99 percent of the cooking. For all commercial sales by gas utilities, the compound annual growth rate in the past ten years has been 8.6 percent.

In the field of industrial processing applications, gas has also enjoyed rapid growth. The cost advantages enjoyed by natural gas are supplemented by other important considerations within the plant, such as ease of control, evenness and quality of heating, and dependability of supply. Industrial gas sales by utilities, including all applications of gas in such establishments, have shown an annual average growth rate of slightly over 6 percent. I do not anticipate any deceleration in this rate in the foreseeable future, unless industrial expansion declines markedly.

The story is somewhat different for air cooling. In the residential market, the operating cost advantages of natural gas have so far been more than offset by higher equipment costs. Our progress in gaining widespread acceptance and use has therefore been disappointingly slow. Substantial research is being devoted to this problem, and within the next few years we anticipate that several additional prominent appliance manufacturers will be marketing more efficient and less expensive residential air conditioning equipment using natural gas. This will enable our industry to obtain a substantial, if not major, share of this rapidly growing market. In commercial and industrial air conditioning applications, this problem is relatively minor. Many gas companies are competing favorably in both operating cost and equipment cost, and are obtaining substantial portions of the market with direct absorption equipment, gas-fired engines, and large-volume steam absorption units. We expect to improve our position even further in these markets in the future, partially through the concept of on-site total energy generation.

Significant consumer interest is already being expressed in the relatively new concept of on-site total energy generation, using natural gas in engines or turbines. In these applications the engine or turbine produces the required electricity on the customer's premises, and the waste heat is employed for heating, air conditioning, and hot water heating. Such installations are completely dependable, and offer important cost savings to consumers who have relatively level load requirements throughout the year. They are generally not feasible for a customer whose electric load fluctuates widely, because of the capital costs of equipment needed only to meet infrequent peaks. Under proper conditions they achieve total system efficiencies significantly in excess of 60 percent. Our new General Office building, nine miles northeast of Aurora, Illinois, has been successfully using this concept for over a year and a half, and is demonstrating dramatically what such installations can achieve for customers. Our market analyses indicate a very substantial potential for such applications, which we intend to exploit fully.

In the future, our industry will be selling fuel cells. These will convert natural gas directly to electricity, silently, efficiently, and reliably, on the premises of the customer. They will be designed primarily for residential and other small users, where engines are not applicable. Substantial funds are being spent, both by the gas industry and by individual manufacturers and research organizations, to hasten the day when such fuel cells will be widely available. We look forward with eager anticipation to the day when no customer, residential, commercial, or industrial, will require any form of energy on his premises other than that supplied through a gas line.

Perhaps the best way of summarizing the aggregate growth of natural gas in the Nation's economy is to provide a chart showing the increases in total energy used in the United States, and the way in which natural gas has contributed to those increases. I have taken the liberty of appending to the historical data a few projections of my own which I regard as "conservatively realistic." In 1940, natural gas provided 11.4 percent of the total; in 1950 it was 18.0 percent; in 1963 it was 29.7 percent; and in 1970 it will provide 32.3 percent.

Continued growth in demand for natural gas obviously raises the question of adequacy of future supply. Many experts have attempted to develop reasonable estimates of total future supplies of natural gas in the United States. I emphasize that they must be estimates, because no one can yet scientifically determine how much gas may exist in a given place and at a given depth before that place has been located and adequate drilling has occurred. The estimates of these experts have ranged between 600 trillion cubic feet and 1,800 trillion cubic feet, with recent estimates generally in the upper range. Even at the midpoint of this scale, some relatively simple arithmetic indicates that supplies will be completely adequate for a considerable number of decades. And we are not limited exclusively to the natural gas which will be found within the limits of the contiguous forty-eight states. Very substantial additional quantities of natural gas will be available to the U.S. by conventional pipeline importation from Canada and Mexico. Less significant, but still important, quantities will be available from tanker shipments in liquefied form from overseas points. Many nations produce large quantities of crude oil, which finds a ready market, and also produce substantial amounts of natural gas with limited local requirements. The development of fleets of refrigerated tankers to transport liquefied natural gas is inevitable, so that natural gas now being wasted in some nations can be effectively and economically delivered to market. For those areas with excess supplies of natural gas which are not too remote from large overseas markets, long-distance under-water pipelines anchored to the ocean floor will become feasible. Such a line across the Mediterranean from Algeria to Southern Europe, has already been discussed.

As a further supplement to natural gas supplies in the United States, we have highly favorable prospects of manufacturing synthetic methane from oil shales, low-grade bituminous coal deposits, lignite, and tar sands. Substantial industry funds have been spent in recent years in researching the processes necessary for such conversion, including the development of small-scale pilot plants. Recently, plans were announced by several Gas Boards in Great Britain to produce a synthetic, high Btu gas from refined petroleum products (primarily naphtha) at a price per therm which even today, before further research, is within hailing distance of natural gas prices in the U.S.

To date, importation of liquefied natural gas and production of synthetic natural gas have not occurred in the United States because they cost more than naturally-occurring methane. However, two factors will gradually eliminate this economic differential. Natural gas (in common with all other mineral and energy resources) will gradually increase in price, as demand increases and natural supplies diminish. The synthetic product, or the natural product from unusual sources, will gradually decline in price as technology improves the applicable manufacturing or marketing processes.

Now that I have reviewed the magnitude of the markets and the adequacy of supplies to meet those demands, let me turn to the economics of utilization. In the first place, I believe that utilization (or sales) is the essential factor in any industry. Unless a product is eventually used and a profit derived, all else is meaningless. The factor which determines the utilization of any given product is its overall economics, both to the manufacturer and/or distributor, and to the consumer. Costs at all levels, for research, production, and marketing, obviously affect consumer economics.

Let me start at the beginning, and discuss some of the economic characteristics of natural gas exploration. This activity is obviously necessary to locate new sources which will replace gas being produced and used, and thus maintain adequate supplies and deliverability for future demands. Exploration for natural gas (or crude oil) is financially hazardous; among those wells drilled in completely new areas (wildcats), only one in ten finds commercial deposits of gas or oil, and only about one in one hundred proves profitable, in spite of all the research on techniques for identifying likely production sites. News accounts often discuss those who have struck it rich, but no one hears about the hundreds of people who have lost their investments completely. The hazards of this business emphasize the need, for the good of the country, to provide adequate incentives to those who risk their money in exploratory activities, and I shall return to this point shortly. Also remember that a disproportionately large percentage of exploration is undertaken by individuals and small independent operators, rather than the giant, integrated oil companies who might be able to spread their risks more effectively. Furthermore, exploration is becoming more costly rather than less, because of increasing concentration on offshore areas and deeper horizons where the possible rewards may be greater, but where drilling costs per foot are very much higher. It is almost axiomatic in any extractive industry that the shallower and more accessible deposits will be found sooner, and that as the industry matures it requires more ingenuity and technological progress to maintain the pace of new discoveries.

Production of natural gas entails a wide variety of complex economic problems. No one knows how much it costs to locate and produce a unit of natural gas. In the exploration phase, it is usually extremely difficult to know whether you will find gas or oil or both if successful; and impossible to know if the hole will be dry or productive before you start drilling. For the 90 percent of exploration which is unsuccessful, how shall the cost be apportioned between gas and oil, remembering that unsuccessful exploration is an integral part of the search to develop new sources of natural gas. For a producing well, where both gas and oil are obtained, how shall the operating costs be allocated between the two products. The Federal Power Commission has been struggling with these basic problems for substantially more than five years in their attempts to regulate the price of natural gas at the wellhead, as the Supreme Court required after the famous Phillips Petroleum decision of 1954. On cost allocations, I don't think they are much closer to a defensible and economically justifiable answer than they were five years ago. An alternative is to ignore cost allocations and cost determination, and set a price for natural gas at the wellhead based on its value as determined by arm's-length negotiation between producer and purchaser. This is the so-called commodity value concept, which the Federal Power Commission has not as yet adopted, preferring instead to explore the cost determination procedure.

Another policy matter involving economic theory is the depletion concept. When a producer sells natural gas he is selling his asset, and part of the price he gets is a return <u>of</u> capital rather than a return <u>on</u> capital. Under our tax laws, the latter is taxable, but the former is not. Contrary to some impressions, depletion is not unique to natural gas and crude oil. The rates may vary, but depletion is available to the smallest property owner growing evergreens for Christmas trees on his property, and to the largest industrial corporation extracting any kind of mineral. Another economic problem is the maintenance of relatively even rates of flow from natural gas wells, to maximize ultimate recovery of the resource in spite of substantial seasonal load variations at the consumer level. Producers have attempted to protect themselves against this problem by institution of take-or-pay provisions in their sales contracts; I shall refer again to this concept when I discuss the economic problems of pipelines.

It should be kept in mind that, to some extent, producers of natural gas have the alternative of selling their product in intrastate commerce, which would free them of the Federal regulatory problems I have discussed. There are substantial intrastate markets for natural gas, consisting of petrochemical plants, other industrial establishments, electric power generation, and local natural gas distributors. When available supplies significantly exceeded interstate market demands, these intrastate markets were insufficient to offer an effective alternative. Now that supply and demand have become more nearly balanced, "excess" supplies have become substantially lower, and intrastate markets have grown substantially, these intrastate markets may assume greater relative importance as an effective alternative for the producer. Such a condition could deprive markets in consuming states located at some distance from producing areas of their needed incremental supplies, unless these economic factors are effectively recognized by regulatory bodies.

The transportation or pipeline segment has some of its own unique economic problems. As alluded to previously, they are faced with take-or-pay provisions in their gas purchase contracts. This means that they must accept some relatively high percentage of the maximum amount of gas available to them, on each and every day of the year, or pay for it anyway. To protect themselves against such provisions, the pipelines generally impose comparable take-or-pay provisions on their distributing utility customers. Pipeline rates almost universally contain two components. The demand charge is a fixed obligation on the customers of the pipeline, to pay a specific amount each month to cover the fixed costs of providing a definite amount of daily capacity for the individual customer. The commodity charge, which varies directly with the quantity of gas sold to the customer, is intended to cover variable costs attributable to volumes transported. The most common take-or-pay provision in pipeline contracts with distributors is that the distributor must take or pay for 75 percent of the maximum amount to which he is entitled each month (daily contract amount times the number of days in the month times the commodity charge). At least one pipeline company is currently attempting to lessen the impact of its take-or-pay provisions in purchase contracts with producers, by developing potential underground storage fields near the producing area. This would permit them to purchase gas from the producers at a relatively even daily rate, and to vary their deliveries to distribution company customers, depending upon market demands, by injections and withdrawals from their own storage field.

Although the demand charge paid by distributors to the pipeline is intended to cover the fixed costs of the pipeline, it does not accomplish this objective under current regulatory practice. Under the so-called Seaboard Formula, the Federal Power Commission allocated 50 percent of fixed charges to demand and 50 percent to commodity, and all of the variable charges to commodity. This policy penalized distribution companies with high load factors, and rewarded those with poor load factors. This phenomenon is demonstrated in Chart 3. I shall not take the time to explain the philosophy under which the Federal Power Commission has employed this allocation method, with its inherent deviation from proper economic principles. Happily, they are currently showing signs of reversing their direction partially, and reverting to a more realistic economic interpretation of cost causation.

Another interesting characteristic of many regulatory agencies is the retention of original cost as the basis for determining allowable return (or earnings). In such cases, no recognition is generally accorded to inflation, replacement cost, or market value of facilities. The pipelines and utilities are permitted to earn a specified percentage of their depreciated original property cost. There are many other ramifications of how this so-called "rate base" is determined, and another equally lengthy paper could be readily written on this subject.

As gas demands continue to grow, particularly in built-up residential and commercial areas, it will be far more practical and economical for utilities to increase operating pressures rather than construct numerous new distributing lines. This will require pipelines to increase their operating pressures to the extent possible, through addition of substantial compressor facilities. Already some pipelines are giving serious attention to this forthcoming problem. I should remind you that underground pipeline transportation of natural gas is one of the most efficient and least expensive methods of energy transportation yet devised. Natural gas pipelines transport 10 percent of the Nation's aggregate inter-city tonnage of freight movements, compared with 20 percent for the entire trucking industry.

The last branch of the gas industry is the one with which I am most personally familiar--the distribution companies. One principal problem is load factor, defined as the ratio between average daily requirements and peak day requirements. In the climatic conditions prevailing in my company's service area, this ratio is 26 percent for residential heating; a residential heating customer uses four times as much gas on the coldest winter day as his average daily use. With the substantial growth in gas heating described previously, this means that distribution companies have substantially lower summer gas requirements than in winter. Unless some method is employed to use this unrequired summer gas profitably, since they must pay fixed demand charges to the pipeline throughout the year, the financial picture of most gas distributors suffers substantially. There are three general approaches to this problem. First, we try to sell gas on a firm basis for applications which have their greatest requirement in the summer, such as air conditioning and swimming pool heating. Unfortunately, this is generally only a very partial answer at present. Secondly, many companies, including my own, have developed underground storage facilities near their markets, into which we inject gas in the summer and withdraw it in the winter to meet the peak requirements. This serves the dual purpose of permitting us to take summer gas from the pipeline at high load factors, and to meet winter peaks without commiting ourselves to substantial new increments of pipeline flow gas with additional fixed demand payments and take-or-pay provisions.

The third alternative is to sell gas to large commercial and industrial establishments on an interruptible or off-peak basis. Such customers utilize coal, oil, propane, or other alternatives when they are interrupted and cannot have natural gas. Since our payments to the pipelines under the demand component of the rate are fixed, the only measurable incremental cost of gas for supplying these customers is the commodity cost. Any revenue obtained from such customers over and above the commodity cost of the gas which they use represents a contribution to pre-tax earnings.

Interruptible and off-peak gas is generally sold in vigorous price competition with other fuels. If regulatory policy followed economic principles, and assigned only variable costs to the commodity component of pipeline rates, the commodity charges would be lower, and our competitive position in this market would be improved. Let me emphasize clearly that our company sells gas to interruptible users only when excess gas is available for which no more desirable alternative exists, and the daily amounts of gas for which we contract with our pipeline suppliers are determined exclusively by the demands of year-round customers.

For distributing companies, operating costs can also be distinguished between fixed and variable components. Certain costs are constant regardless of the amount of gas used by the customers. Other costs are variable depending upon customer usage. This is the economic justification for the typical block rates used by gas utilities, under which large users earn progressively lower charges per unit of consumption. Unfortunately, in many parts of the country the differential levels of these various blocks cannot reflect realistically the proper application of economic and cost principles. To do so would require the imposition of substantially higher charges in the initial block of consumption, and require higher minimum bills per month, than is ordinarily palatable for regulatory bodies sensitive to the social pressures of the vast numbers of small users.

Much regulatory attention, but little action so far, is also being accorded to the question of managerial efficiency. Presumably, a utility which is efficient in providing superior service at low costs to the maximum number of potential customers should be entitled to higher earnings (rate of return times rate base) than a company which fulfills these desirable objectives less satisfactorily. I hope and anticipate that this concept will be more generally recognized and employed in regulatory decisions in the future.

Another significant economic problem for many gas distributing companies is the impact of inflation upon their investments, where state regulatory commissions still employ original cost for a past period as the basis for determining allowable earnings for the future. The trends toward suburbanization and less dense customer concentration, combined with higher unit investment costs because of inflation, have generally increased the average investment per customer of gas companies. This necessitated (until relatively recently) relatively frequent rate increases to consumers. The best solution to this problem is vigorous and effective sales promotion to increase the amounts of gas used by each customer, so that the higher investments will be utilized more fully throughout the year, thus providing more satisfactory contributions to earnings.

What are the challenges to research and technology in the economic problems of the gas industry? What research advances will improve the industry's efficiency, offer greater economies to consumers, and provide more effective resource utilization for the entire Nation?

Let me start again with exploration and production. At present, we can, through seismological, geological and geophysical procedures, locate presumably favorable underground structures, but we can not tell (other than by drilling an expensive hole) whether there will be hydrocarbon accumulations encountered. Research is continuing using geochemical approaches, and some experiments with laser beams, but it would be a massive step forward if a method existed to determine whether there were indeed hydrocarbons located many thousand feet beneath the earth's surface.

Technological improvements are continually needed on drilling techniques and well completion methods, as exploration goes deeper. Exploration increasingly involves wells 20,000 feet deep or more. At such depths, we need greater strength in drill pipe, more efficient and longer-lasting bits, and cement which will not set too quickly and with sufficient permanent strength at high temperatures (400°+). The entire science of mud formulation is amenable to further research and technological advance. Mud serves three basic purposes: it lubricates and cools the drill bit, it removes pieces of ground-up rock formation from the hole, and it seals off any formations through which drilling has penetrated. In many formations, existing muds do not always satisfactorily perform these three functions. More efficient means of fracturing formations are needed, to facilitate extraction of hydrocarbons without damaging the rock structure.

It appears that foreseeable advances in gas transportation are largely problems of extending existing technology, rather than developing new techniques or conducting additional research. It is likely that larger diameter line pipe (perhaps 42" or 48") might be desirable. More likely is the probability of using existing pipe sizes at higher pressures, which may require higher strength steels and more efficient compressors. The use of gas turbines for compressor stations, now becoming increasingly common, may be an answer to one part of this problem. There will also be considerable extension of the concept of complete automation of long-distance pipeline systems, with electronic data gathering and controls at one central point, automatically correcting pressures and gas movements for varying load conditions at any point along the line.

In the field of gas distribution and customer utilization, there are many areas where research will be important. Much remains to be done in developing more effective and less costly techniques for synthesizing natural gas from coal, oil shale, tar sands and other materials. The development of reliable and marketable fuel cells, to convert natural gas directly into electricity on residential premises, is still in its infancy, and major new advances are anticipated. The future will undoubtedly provide us with new types of plastic pipe with extremely long life, inexpensive installation, freedom from corrosion and chemical attack, and able to withstand intermediate, or even high, pressures. The development of more efficient thermoelectric corrosion prevention techniques for steel pipe is needed.

More research is required to develop residential absorption gas air conditioning with greater efficiency and lower first cost. This may possibly involve the development of better chemical systems than the present lithium bromide medium. Greater combustion efficiency in residential applicances, particularly gas furnaces, would be a major step forward in true conservation of a vital natural resource. Gas furnaces which now operate at 75 percent efficiency are the most efficient overall way of heating homes, but if they operated at 85 percent it would significantly extend the life of our available natural gas reserves. More research is needed on thermoelectric devices to convert the waste heat of furnaces directly into electric power to operate the fans and blowers on warm air systems, so they may be independent of outside electric power and be free of outages during storms or catastrophe.

Further advances will occur in developing less costly gas engines and turbines, and in providing more efficient automatic instrumentation and control panels for such units. Initial experimentation is already being conducted on remote meter reading using telephone lines, but I foresee further advances, possibly using radio transmitters and receivers in gas company patrol cars driving through neighborhoods.

I hope I have provided you a reasonably comprehensive picture of the current and future status of gas utilization in the United States, and of some of the economic problems affecting all phases of the industry from wellhead to consumer. I also trust that some of the challenges to research and technology which I have mentioned will excite your imagination. We need the assistance of all types of scientists throughout the country so that, in the consumer interest, we can improve the performance and efficiency, and lower the costs, of our Nation's fifth largest industry, the natural gas industry.

Chart 1

Cooking Fuel in the U.S., 1940-1960

	Gas[a]	Other or None	Total Occupied Dwelling Units
Number (000's)			
1940	17,026	17,828	34,854
1950	25,502	17,324	42,826
1960	33,730	19,082	52,812
Percent			
1940	49	51	100
1950	60	40	100
1960	64	36	100

(a) Includes bottled gas.
Source: 1960 U.S. Census of Housing

CHART 2

Energy Used in the U. S. by Principal Sources
1940-1970

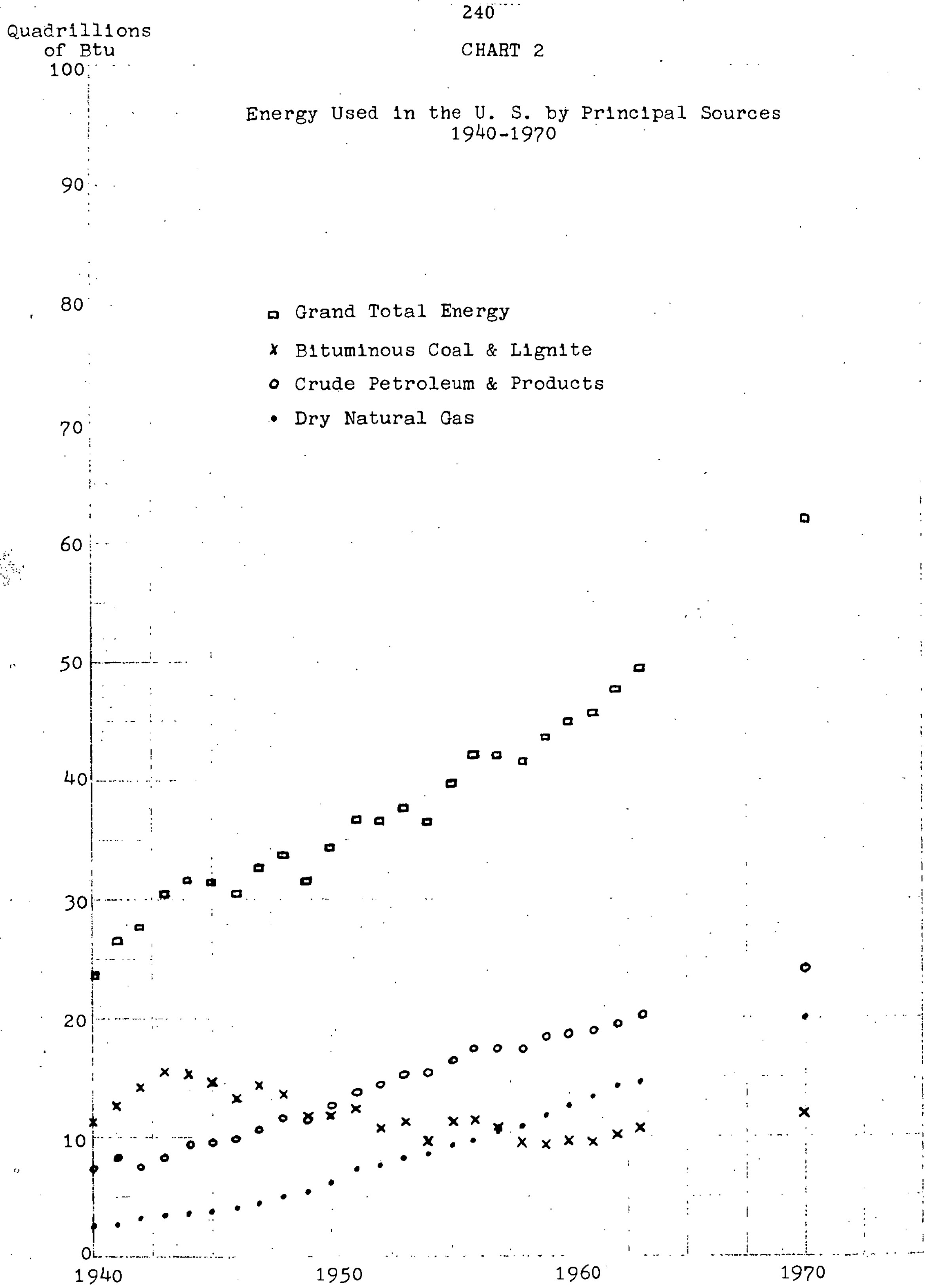

Chart 3

Effect of Two-Part Rates and Seaboard Formula on Average Cost of Gas

1. Assume a fictitious pipeline with:

   maximum daily capacity of 2,000,000 MCF
   annual sales of 500,000,000 MCF
   fixed costs of $80,000,000
   variable costs of $70,000,000

"True Economic" Rate		"Seaboard" Rate
$3.333/MCF/mo.	demand	$1.667/MCF/mo.
plus 14.0¢/MCF	commodity	plus 22.0¢/MCF

2. Assume two distributing utility customers with:

A		B
200,000 MCF/day demand 90% load factor		200,000 MCF/day demand 50% load factor
	"True Economic" Rate	
$ 8,000.000	Demand	$ 8,000,000
9,184,000	Commodity	5,096,000
$17,184,000	Total Cost	$13,096,000
65,600,000	Total Purchases	36,400,000
26.15	¢/MCF	35.95
	"Seaboard" Rate	
$ 4,000,000	Demand	$ 4,000,000
14,432,000	Commodity	8,008,000
$18,432,000	Total Cost	$12,008,000
65,600,000	Total Purchases	36,400,000
28.15	¢/MCF	33.00

ECONOMICS OF THE UTILIZATION OF ELECTRICITY

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Electricity is a highly sophisticated and somewhat abstract form of energy. Once produced, usually from some source of thermal energy, electricity exists but a fraction of a second before being consumed in useful work. About 35 to 40 percent of the original thermal energy reaches the ultimate consumer. Taking competitive advantage of this situation, gas and oil interests are currently promoting the concept of delivery of energy in fossil fuel form to the consumer, with on-site conversion to electrical energy. Judicious use of thermal energy, normally wasted in the conversion process, permits overall theoretical efficiencies approaching 80 percent. The user of energy must therefore decide not only what form of energy to use at the point of utilization, but, if the choice is electricity, whether to purchase it directly or to produce it himself.

The choice of electricity at the point of utilization is mandatory for those devices that depend on the peculiar characteristics of electricity, such as electronic devices and clocks. Electricity may be chosen simply because building a fire is not convenient for such devices as toasters, irons, small motors and interior lights. Economics may dictate the choice of electricity or other energy sources for heating and cooling devices and large rotational loads.

Convenience, as well as economics, dictates that electricity be purchased for users of relatively small quantities of energy such as residences and small commercial establishments. For large users of energy, such as industrial plants and some large buildings, economics is the over-riding criterion for deciding whether to purchase electricity or to generate it locally.

The remainder of this paper is devoted to two presently important areas of energy source competition: first, the economics of local generation instead of purchased electricity for commercial buildings, and second, the utilization of electricity for environment conditioning.

ISOLATED GENERATION ECONOMICS

An isolated generation system currently being promoted for energy supply to commercial buildings consists of gas turbine or natural gas engine generation combined with a means of waste heat recovery. The generation supplies lighting, motor, and other miscellaneous electric equipment. The waste heat recovery equipment supplies various thermal requirements such as hot water, heating and steam absorption refrigeration machines for air conditioning. The economics will favor isolated generation only if the energy cost saving afforded by the isolated generation system, compared to conventional energy supply, more than offsets the additional capital expenditures required for the isolated generating and waste heat recovery equipment. The following economic analysis was performed in order to obtain a rough evaluation of the isolated generation concept.

A 64,000 square foot office building was selected for study to represent an average size office building requiring a typical rating of an isolated generation plant. Twelve major cities scattered throughout the United States were studied in order to represent different climates and relative rates for electricity and gas. The simple gas turbine system was selected because this system is being promoted at the present time as having the greatest long-range potential.

For each of the twelve cities, the two basic methods of energy supply which are considered are summarized as follows:

Conventional: Electric utility supplying basic electric loads and electric drive refrigeration machines for air conditioning. Gas utility supplying in-building boiler which produces steam for heating, hot water, and other miscellaneous uses.

Isolated Generation: Gas utility supplying gas turbine generator units, which in turn supply electricity for the basic electric loads, and, through a waste heat boiler, supply steam for heating, hot water, steam absorption refrigeration machines for air conditioning, and other miscellaneous uses. All electric loads are supplied at a frequency of 60 c.p.s.

The isolated generation system consists of two normally operating turbine generator sets with a third set used as a spare. Generating frequency is 60 cycles per second. Each turbine generator set is rated at 254 KW with the following conditions: sea level, 70° F. inlet air temperature, two inches of water inlet pressure loss, and eight inches of water exhaust pressure loss.

Energy Cost Analyses

All of the energy cost analyses were made using a special digital computer program developed for that purpose.1 A simplified logic flow diagram of the computer program is shown in Figure 1. The program synthesizes the hourly steam and electrical loads in the building based on hourly schedules of building usages, building physical characteristics, hourly solar angles and radiation intensities and complete hourly weather data for each of the cities. The weather data is available in card or magnetic tape form from the United States Weather Records Center. Once the hourly loads are synthesized, the program simulates the operation of the conventional or on-site energy supply system in order to calculate hourly input energy requirements. The last step in the program is to apply specific utility rate schedules to the input energy requirements in order to determine monthly energy costs. This program is coded for use on an I.B.M. (International Business Machines) 7094 digital computer.

Annual Owning and Operating Costs

Additional equipment required for the isolated energy supply system is listed in Table 1. Two sets of cost figures are included: present prices based on current price estimates, and predicted prices based on the isolated generating concept achieving sufficient acceptance to result in high volume production of the gas turbines.

The annual costs of the capital expenditures required by the isolated generation system are based on a capital recovery factor of 8.7 percent which, in turn, is based on an amortization period of 20 years and a return of six percent on the undepreciated investment. An additional 2.5 percent is included for taxes and insurance. Thus the annual fixed charge rate is 11.2 percent.

The total annual owning and operating cost, excluding fuel, of the isolated system is the sum of the fixed charges and the maintenance costs, as listed in Table 2. This cost is then to be compared with the saving in energy cost associated with the on-site system.

Economic Results

The results of this economic analysis are shown graphically by Figure 2. The bar graphs represent the saving in annual fuel cost of the isolated generation system compared to the conventional system. The horizontal lines represent the increase in owning and operating costs (excluding fuel) chargeable to the isolated generation system.

The results show that the isolated generation concept is not the economic choice in any of the twelve cities when considering present price estimates. Using predicted future production prices, the isolated generation concept would be the economic choice for this building in Chicago and Atlanta and would be marginal in Minneapolis, St. Louis and Jacksonville.

ELECTRICITY FOR ENVIRONMENT CONDITIONING

Electricity may be utilized for environment conditioning in two basic manners. Electrical energy may simply be converted back to thermal energy and directly used for space heating. Even though this energy reconversion is accomplished at 100 percent efficiency, the overall efficiency from the thermal energy at the power plant to the utilization point remains at 35 to 40 percent. Thus it is difficult for electricity to compete on a strictly energy cost basis with a fossil fuel system having an overall efficiency of about 65 percent. This situation is demonstrated by Figure 3A which shows the number of cities, out of a selected sample of 26, that have the indicated ratios of gas heating costs to electric heating costs for residences. The cost ratios apply to energy only and assume an overall gas system efficiency of 65 percent, and that a 10 percent savings can be realized with the electric heating system through the use of diversified temperature control.

One must be aware, of course, that the total economic picture includes first costs of the systems, differential structure costs and maintenance costs, all of which tend to favor electric resistance heating over a fossil fuel system. This is substantiated by the fact that electric resistance heating is quite commonly utilized in certain areas of mild climates, where, regardless of the competitive rate situation, total heating energy bills are relatively low.

Electricity is a uniquely convenient means of supplying rotational loads over a complete spectrum of magnitudes. Consequently the second means of utilizing electricity for environment conditioning is through the use of electric motor-driven refrigeration compressors. These devices may be either refrigeration units just for cooling, or heat pumps for both heating and cooling.

Electric motor-driven refrigeration units compete quite favorably with any other type of cooling on the basis of first costs and operating costs. Consider, for example, the 300-ton steam absorption and electric drive centrifugal refrigeration machines studied in conjunction with the isolated generation system reported previously in this paper. The steam absorption machine, compared to the electric-drive machine, required 7.25 times as much energy to the machine itself, 25 percent more auxiliary power, and cost over 15 dollars per ton more in first cost. Economically justifying the steam absorption machine would be difficult unless the steam or fossil fuel were very inexpensive by-products of another process, or the electrical energy were unusually expensive.

The heat pump improves, to a considerable extent, the ability of electricity to compete with fossil fuels on the basis of heating energy cost. This reverse-cycle refrigeration unit permits the utilization of free heat available from such mediums as the outside air. A typical performance factor for a residential air-source heat pump is two. This may be considered to be an annual efficiency of 200 percent, considering electricity as the only chargeable input energy source. The relative significance of the heating energy cost for a residential heat pump may be seen by Figure 3B. Since the heat pump is a central system, no savings is assumed for diversified temperature control. Note that the heat pump is competitive on the basis of energy costs in about one-third of the cities. Because of first cost considerations, the heat pump is used primarily in areas where air conditioning is desired in addition to heating.

CONCLUSIONS

The isolated generation analysis presented in this paper is but one of many performed by the author on buildings ranging in size from under 100,000 square feet to over 500,000 square feet.1 Isolated generation has not proved to be the present-day economic choice in any of these studies. For isolated generation to have been economical would have required a higher than usual thermal load factor, and either none or relatively low financial return required on the additional capital expenditure.

Electric resistance heating is not generally the economic choice of space heating energy source in areas with an adequate supply of fossil fuels. In spite of the economics, however, electric heating is growing in use, seemingly because of the combined effects of general desirability and at least acceptable costs. Electricity is the economic choice in many areas over fossil fuels for environment heating and cooling through the use of a heat pump.

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TABLE 1 - ISOLATED GENERATION EQUIPMENT COSTS

	TOTAL COSTS FOR QUANTITY REQUIRED		
	Quantity	Present	Production
Turbine-generator set complete with mounting arrangement, protection, inlet air cooler (evaporative) and controls. 254 KW output.	3	$ 179,800	$ 96,300
Gas booster, battery charger, gas compressor and storage tank for start-up	1	9,200	9,200
Boiler (differential cost)	1	8,000	8,000
Absorption refrigeration machine (differential cost)	1	4,700	4,700
Floor space (300 square feet)	1	6,000	6,000
Installation	1	25,000	25,000
Sub-Total		$ 232,700	$ 149,200
Engineering (7.5 percent)		17,400	11,200
TOTAL		$ 250,100	$ 160,400

TABLE 2 - ANNUAL OWNING AND OPERATING COST
OF ISOLATED GENERATION SYSTEM EXCLUDING FUEL

Item	Present Cost	Production Cost
Capital Recovery[1]	$ 21,800	$ 14,000
Taxes and Insurance[2]	6,200	4,000
TOTAL FIXED COST	$ 28,000	$ 18,000
Turbine Maintenance[3]	1,800	1,200
TOTAL ANNUAL COST EXCLUDING FUEL	$ 29,800	$ 19,200

1. Six percent return, 20-year depreciation: 8.7%
2. 2.5%
3. $.15/turbine hour - present cost
   $.1/turbine hour - production cost

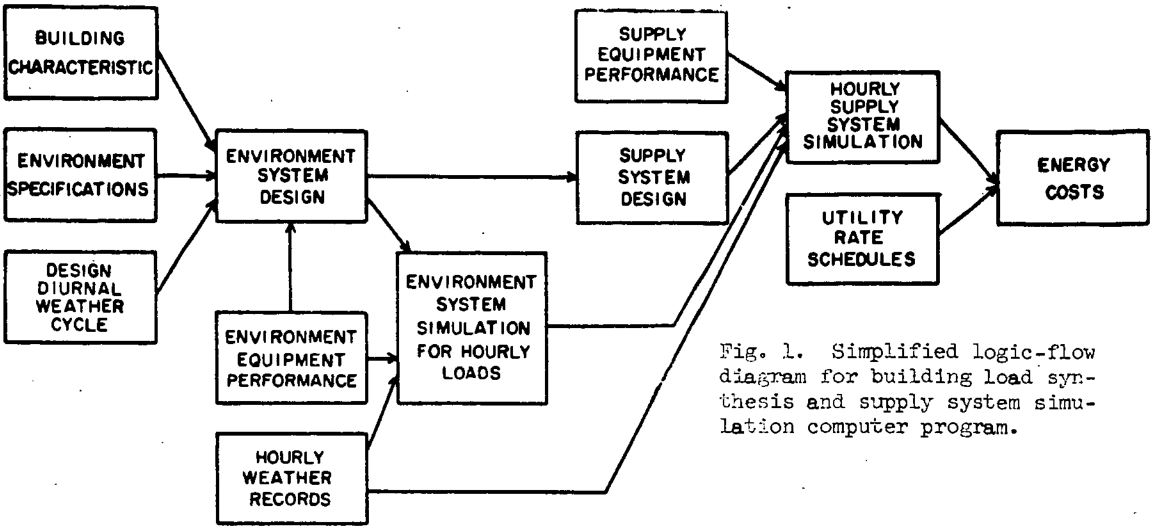
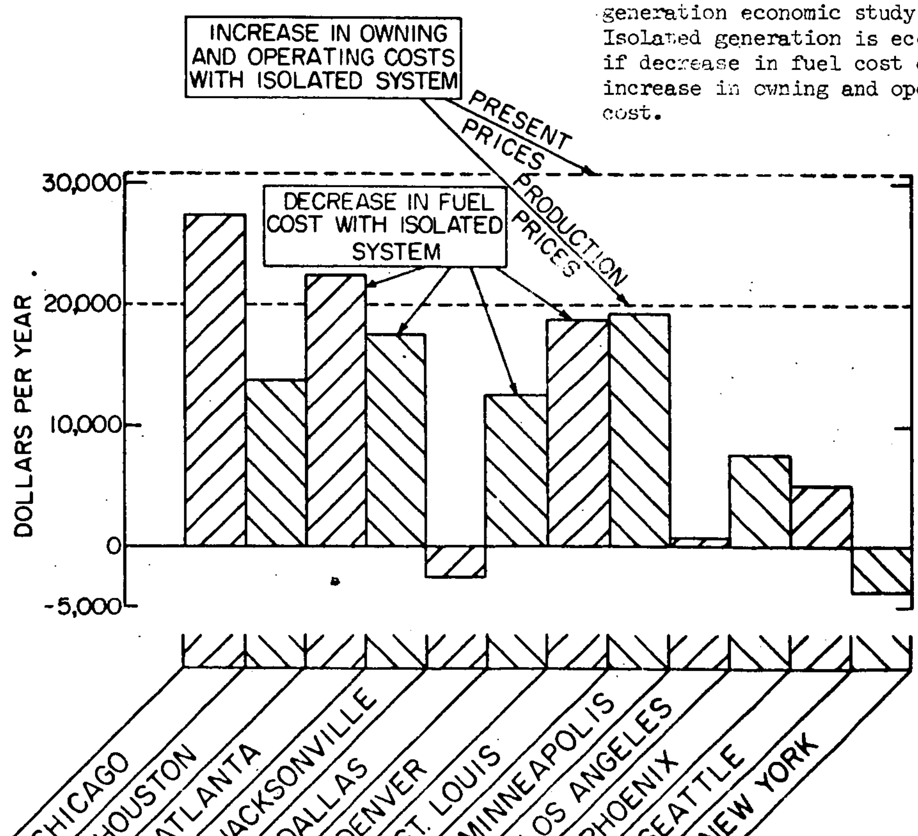


Fig. 1. Simplified logic-flow diagram for building load synthesis and supply system simulation computer program.

Fig. 2. Results of isolated generation economic study. Isolated generation is economical if decrease in fuel cost exceeds increase in owning and operating cost.



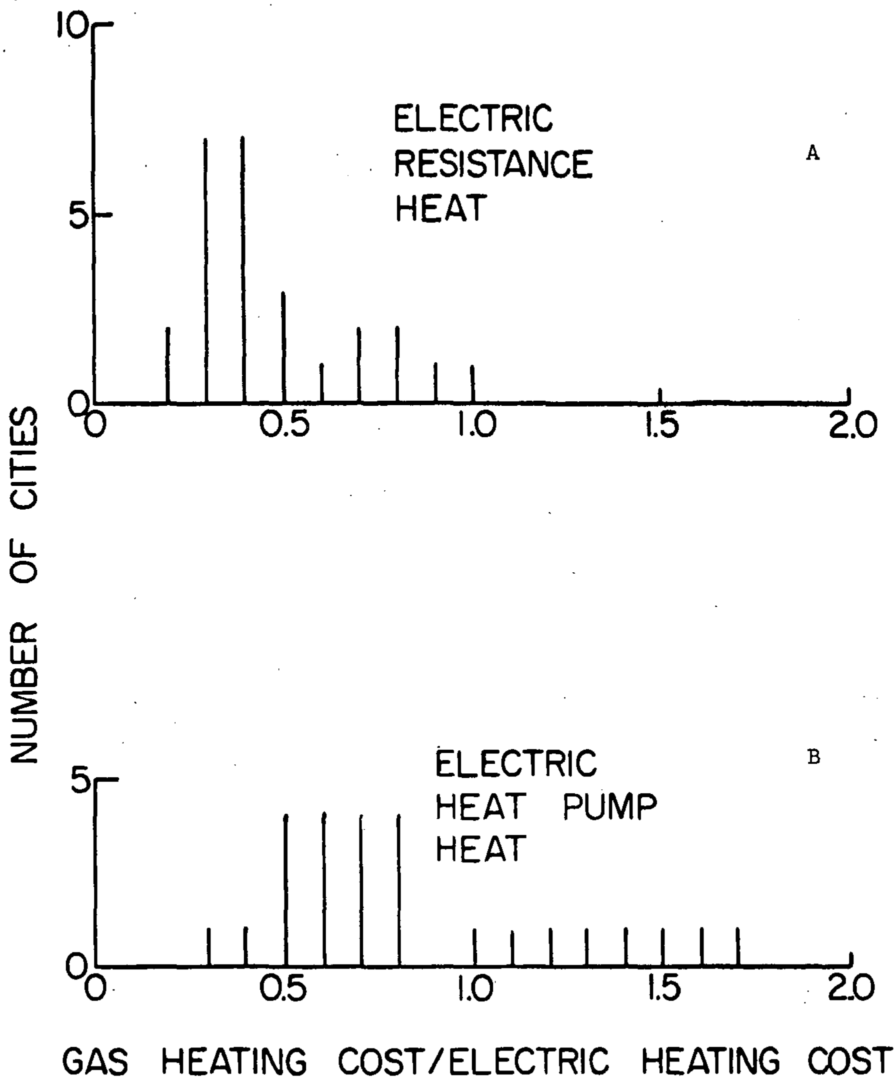


Fig. 3. Ratio of gas heating cost to electric heating cost for 26 U.S. cities. A - Resistance heat. B - Heat pump heat.

PREPARATION OF BIODEGRADABLE SYNTHETIC DETERGENTS FROM LOW-TEMPERATURE LIGNITE TAR

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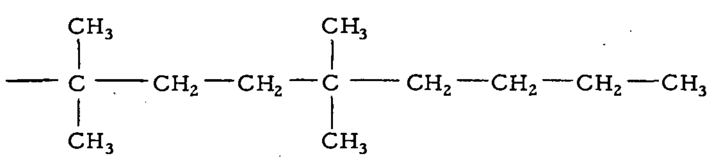
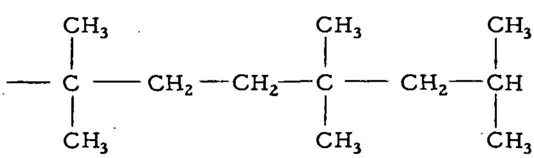
INTRODUCTION

Search for biodegradable synthetic detergents from low-temperature tar is part of a broad research program on low-temperature coal tar by the Bureau of Mines, U. S. Department of the Interior. Fundamental objectives of this research on tars resulting from the low-temperature carbonization of coal are to (1) characterize these tars in some detail; (2) investigate means of upgrading them economically into marketable products; and (3) obtain information that can increase production of coal for use in carbonization through establishment of a coal-chemicals industry based on the utilization of low-temperature tars.

Synthetic detergents in waste water is a controversial topic. Branched-chain alkylbenzene sulfonate (ABS), the principal surfactant used in detergents, is difficult to remove from waste water because of its resistance to biological degradation. Conventional ABS is also being blamed for many sewage plant foaming problems (12). As a result, extensive research is being conducted in this country and abroad on producing a "soft" type of ABS (3), one that is more easily degraded by the bacteria present in sewage plants than is the conventional ABS. Conventional ABS consists of a mixture of mono-substituted benzenes, the alkyl substituent being highly branched, e. g. :



and



No evidence has been found of the presence of methylene chains exceeding three carbons. "Soft" ABS, on the other hand, has less branched alkyl chains than the old "hard" ABS and contains methylene chains exceeding three carbons, e. g. :

$$—(CH_2)_{10}—CH_3 \quad \text{and} \quad —\underset{\displaystyle CH_3}{\underset{|}{CH}}—(CH_2)_9—CH_3 .$$

Low-temperature lignite neutral oil fractions contain as much as 17 to 20 percent alpha olefins in addition to trans-internal and tertiary ones (9). These olefins are valuable as charge stock for the synthesis of alcohols, acids, and surfactants for detergents. Other Bureau scientists have demonstrated the feasibility of producing alcohols (1). This report covers laboratory-scale research on the preparation of biodegradable alkylbenzene sulfonates (ABS) using straight-chain olefins extracted from a low-temperature Texas lignite tar.

EXPERIMENTAL

Preparation of Feed Stock. - The tar used in this study was produced from a Texas lignite carbonized at about 950°F by the Parry carbonization process (10). The crude tar was vacuum distilled (25" Hg) to an atmospheric pressure end boiling point of 350°C. Distillation cutoff temperature of 350°C was chosen because the pitch residue has a softening point of 110°C, the generally accepted softening point for use of pitch as electrode binder. Under these distillation conditions, yields were as follows:

	wt pct
Distillate	51.2
Pitch	43.7
Water	2.1
Distillation losses	3.0

The distillate consisted of:

	wt pct
Tar acids	31.0
Tar bases	3.9
Neutral oils	65.1

The tar acids and bases were removed from the distillate by conventional caustic-acid extraction. A fluorescent indicator adsorption analysis of the neutral oil fraction showed 51.9 pct aromatics, 37.0 pct olefins, and 11.1 pct paraffins.

Urea Adduction. - Straight-chain olefins and paraffins were removed from the neutral oil by the urea adduction method (5, 7).

The general technique involved thorough mixing of neutral oil, urea, and a solvent for one hour at room temperature. Methanol was chosen as the solvent. The crystalline adduct and excess urea were recovered by vacuum filtration and washed with 2,2,4-trimethylpentane to remove unadducted neutral oil components. A sufficient amount of water was added to the crystals to decompose the adduct. The ether solution was placed in a flask, and the solvent was removed at room temperature by a stream of nitrogen. As shown in Table 1, yields of pure product ranged from 12.0 to 15.0 pct. The extracted material was distilled to an end temperature of 300°C. The fraction 170° to 300°C containing the C_{10} to C_{16} normal olefins was considered suitable for detergents. Infrared analysis of the product showed a strong concentration of alpha olefins with a trace of branched chains.

The 170° to 300°C fraction subsequently was analyzed by gas-liquid chromatography by an established procedure (2). Table 2 gives the retention times of some paraffins and olefins, and their relative retentions referred to n-dodecane. Figure 1 is the chromatogram. Volume percentages of the different compounds were calculated by measuring the peak heights and multiplying the results by the peak width at half peak height. Test results are given in Table 3.

Preparation of Alkylbenzenes. - Alkylation experiments were conducted using the 170° to 300°C fraction of the urea adduction product as the alkylating agent. Benzene was alkylated on a semimicro scale using established procedures (11). Benzene and anhydrous $AlCl_3$ were charged to a 150 cc flask equipped with stirrer, thermometer, and separatory funnel for the addition of the alkylating agent. The straight-chain olefin-paraffin mixture was added over a 30-minute period. Additional catalyst was added at 10-minute intervals following initiation of reaction to maintain a maximum reaction temperature of 55°C. Following the addition period, 15 minutes was allowed for stirring and completion of the reaction. The acidic mixture was cooled to room temperature and neutralized by the addition of 20 pct NaOH solution. The catalyst and benzene-rich layers were then separated by successive water washings in a separatory funnel, after which the product was fractionated into three cuts on a 10-inch Vigreaux column. The cuts included benzene, an intermediate composed of paraffins and unreacted olefins, and alkylbenzenes. The alkylbenzene fraction was analyzed by infrared spectrophotometry, and the presence of alkylbenzenes was confirmed; no alpha olefins were detected. Yields calculated from distillation data are reported in Table 4.

Sulfonation of Alkylbenzenes. - Liquid SO_3 was vaporized into a metered air stream, and the mixture was introduced into a 100 cc flask containing alkylbenzenes (8). The flask was equipped with a thermometer and submerged gas-inlet and outlet tubes; agitation was provided by the SO_3-air flow. The SO_3 (14 g) was bubbled into the alkylate (40 g) for approximately one hour. External cooling was necessary to maintain a reaction temperature of 50° to 60°C with an air rate of 1,350 cc/minute. The reaction mixture was neutralized with 60 cc of 10 pct NaOH solution producing a light tan slurry.

Figure 2 is a simplified flow diagram for preparing the C_{10} to C_{16} alkylbenzene sulfonate. The percentage figures given in the flow diagram are the weight-percent of the product versus the input feed to each individual processing step. Fifty pct of the n-olefin-paraffin mixture is within the desirable range of C_{10}-C_{16}. The remaining 50 pct is concentrated chiefly in the high boiling fraction (>300°C) and consists of a mixture of C_{17}-C_{20} olefins and paraffins. Investigations are in progress to increase the yield of usable alkylbenzenes. These include the thermal cracking of the high-boiling paraffins to give C_{10}-C_{16} olefins and the direct conversion of the olefins to alkylbenzenes by eliminating the urea adduction step. When these results are available, an economic study of the process will be made.

Biodegradability Tests. - A sample of the alkylbenzene sulfonates was submitted to the United States Testing Company, Inc., Hoboken, N.J., for determination of its biodegradability. The test procedure used was that adopted by the West German Government (6) as no standard has been prescribed as yet by the United States. This procedure for evaluating surfactant biodegradability calls for the use of a continuous activated sludge waste-water treatment test.

RESULTS AND DISCUSSION

The percent decomposition of the methylene blue active substance (MBAS) was calculated daily. These values are given in Table 5 and shown graphically in Figure 3. A summary of the results is given in Table 6. The presence of 5.6 pct soap found in the test sample undoubtedly represents sample contamination. The biodegradability of the sulfonate sample averaged 99.52 pct. The West German law specifies that decomposability of acceptable anionic detergents must be at least 80 pct (arithmetic mean) (4).

CONCLUSIONS

Straight-chain olefins and paraffins were extracted from a low-temperature lignite tar neutral oil fraction by urea adduction. Infrared analysis of the adducted product revealed no urea contamination and a strong concentration of alpha olefins with only a trace of branch-chain olefins. The 170° to 300°C fraction (C_{10}-C_{16}) of the olefin-paraffin mixture was used to prepare a mixture of alkylbenzenes which, upon sulfonation, gave a synthetic detergent that was 99.52 pct biodegradable.

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TABLE 1. - Urea adduction of straight-chain aliphatics from neutral oil

Charge, g	Methanol, cc	Urea, g	Ether/H_2O, cc	Pure product, wt pct
75	20	45	50/150	12.0
17.5	445	87.5	50/150	12.7
500	300	500	150/500	15.0

TABLE 2. - Retention times of pure olefins and paraffins

Compound	Retention time[1] (minutes)	Relative retention[1] (to n-dodecane)
n-Decane	1.59	0.43
1-Decene	1.77	0.48
n-Undecane	2.43	0.66
1-Undecene	2.70	0.74
n-Dodecane	3.66	1.00
1-Dodecene	4.05	1.32
n-Tridecane	5.52	1.51
1-Tridecene	6.12	1.67
n-Tetradecane	8.34	2.28
1-Tetradecene	9.24	2.52
n-Pentadecane	12.63	3.45
1-Pentadecene	13.89	3.80
n-Hexadecane	19.02	5.20
1-Hexadecene	21.06	5.75

[1] Corrected for air.

TABLE 3. - Quantitative analysis of C_8 to C_{16} α-olefins and paraffins

Compound	Vol., pct
Trimethylpentane	Trace
n-Octane	Trace
1-Octene	Trace
n-Nonane	0.8
1-Nonene	0.9
n-Decane	3.5
1-Decene	3.9
n-Undecane	5.5
1-Undecene	6.5
n-Dodecane	7.2
1-Dodecene	8.0
n-Tridecane	7.6
1-Tridecene	8.8
n-Tetradecane	7.7
1-Tetradecene	8.6
n-Pentadecane	8.3
1-Pentadecene	8.4
n-Hexadecane	8.1
1-Hexadecene	6.3
	100.0
Paraffins	48.7
Olefins	51.3

TABLE 4. - Synthesis of alkylbenzenes

Wt ratio, benzene/feed	$AlCl_3$ catalyst, wt pct	Reaction conditions		Yield, pct[1]
		Temp., °C	Time, min	
4.6[2]	1.8	40-55	45	89.5
4.6[3]	2.1	50-55	45	45.0

[1] Weight-percent, alkylbenzene/feed.

[2] Commercial C_{11} to C_{15} alpha olefins.

[3] Olefin-paraffin mixture (neutral oil 170° to 300° C) (C_{10} to C_{16}).

TABLE 5. - Percent MBAS biodegraded per day

Day of test	MBAS biodegraded, pct	Day of test	MBAS biodegraded, pct
8	95.4	19	100.0
9	94.0	20	100.0
10	100.0	21	100.0
11	100.0	22	100.0
12	100.0	23	100.0
13	98.8	24	100.0
14	100.0	25	100.0
15	100.0	26	100.0
16	100.0	27	100.0
17	100.0	28	100.0
18	100.0	29	100.0
		30	100.0

Decomposability mean value, 99.48 pct

TABLE 6. - Summary of biodegradability tests

	Percent
MBAS in alkylbenzene sulfonate	66.3
Soap in sample	5.6
Average of decomposability values for 23 consecutive days following break-in period	99.48
Decomposability of the detergent (including soap[1]) in the sample	99.52

[1] Calculated from Part I, No. 7, Specification of West German Government Ordinance.

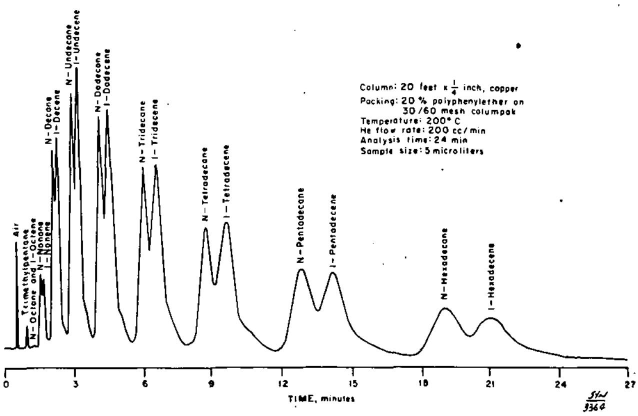

FIGURE 1.
Chromatogram of C_8-C_{16} olefin-paraffin mixture.

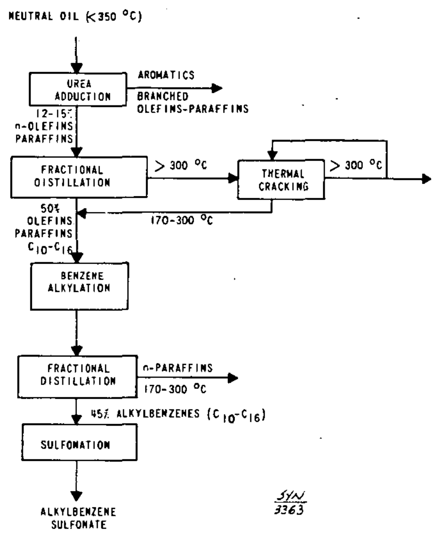

FIGURE 2.
Proposed process for utilization of normal olefins in low-temperature tar.

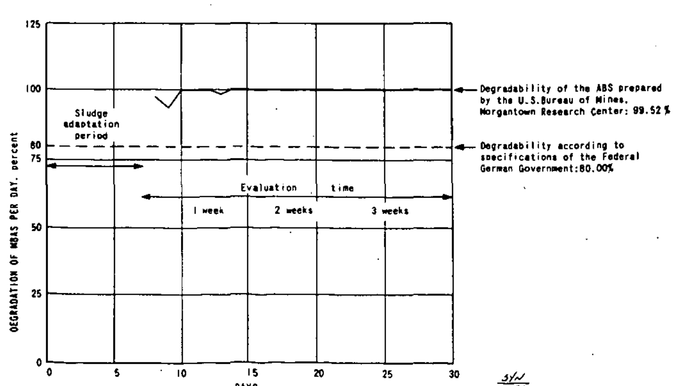

FIGURE 3.
Degradation of methylene blue active substance.